Electricity Costing and Pricing Study

Volume IX

Interruptible Power Study

October, 1976

ELECTRICITY COSTING AND PRICING STUDY

VOLUME IX
INTERRUPTIBLE POWER STUDY

Ontario Hydro
October 1976

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I. INTRODUCTION

This volume provides a comprehensive analysis of interruptible and scheduled power. It discusses present and future applications, examines and evaluates the underlying principles of supply conditions and pricing, and develops recommendations for future supply, pricing, and marketing-methodologies. The proposals are directed towards the efficient use and sale of interruptible power.

The evaluation considers what interruptible power supply conditions can be used to the advantage of the power system, the savings associated with this use, and the requirements or needs of industry in Ontario.

Section II discusses the characteristics and value of interruptible power. The commodity or service is defined, and its relationship and worth to Ontario Hydro and Ontario industry are outlined.

Section III examines conditions of supply for both interruptible and scheduled power, including the contractual limits to use and delivery and the effects system performance and variability have upon the service, and develops a methodology for deciding how much interruptible power to place on the market.

The last section analyses the present and proposed pricing systems for interruptible power. The present system is illustrated, and its advantages and disadvantages are discussed. The proposed pricing approach is then outlined theoretically and operationally, and recommendations are offered about how to introduce and apply it.

SUMMARY OF RECOMMENDATIONS

The following is a summary of the recommendations arising from this study. Some of the more specific and technical proposals are broadly covered by a single recommendation.

1. In 1978, Ontario Hydro should base its fixed discounts for interruptible power on a fixed sum of dollars, based on deferred generation planned in 1973 and the forecasted billing KW for 1978 according to the official load forecast for that year.
2. In 1978, Ontario Hydro should discontinue using Class-B interruptible power to effect daily economy savings.
3. Ontario Hydro should offer its large-use customers two types of capacity interruptible power: one, designated Class 1, with a higher risk, to be used as ready reserve as well as for system emergencies; and the second, designated Class 2, with a lower risk, to be used for system emergency conditions only, subject to thirty minutes' notice to conform with system requirements for slow-pickup reserve.
4. The minimum contract amount should remain at 5000 kilowatts, until some more practical way to measure loads and give notice to cut can be introduced.
5. An automatic transmittal system for load information, such as telemetering, should be installed, to provide the system control centre with totalized data for the loads of all customers taking interruptible power.
6. Any customer that switches from interruptible to firm power, without providing five years notice, should be liable to interruption during the next five years before any other firm customer, if cuts in firm load become necessary; and the amount of load liable to cutting should equal the customer's maximum interruptible load in the previous five years. Furthermore, the cutting-order should be chronologically based: that is, those customers that most recently left interruptible-power contracts should be cut ahead of other designated customers. Furthermore, failure to cut on request should incur a surcharge of 50 per cent on the firm demand rate applied to the amount of load designated as interruptible.
7. Interruptible-power contracts should provide for cutting five days a week, Monday to Friday, with maximum cuts of five hours a day during March to November inclusive and 10 hours a day during December to February inclusive. Moreover, maximum cuts should be set at two a day, 10 per cent of the hours in any month, and 10 per cent of the hours in any year, subject to alteration as required to meet changes in system conditions.
8. In 1978 Ontario Hydro should discontinue offering both scheduled power class C and Valley-Hour power, and offer the present class-C customers the choice of converting to either firm power or interruptible power Class 1 or 2.
9. Interruptible power should be offered to large-use customers of municipal utilities under the same terms and conditions that apply to customers of Ontario Hydro.
10. In offering interruptible power for sale, Ontario Hydro should provide the customer with estimates of the probable frequency and duration of interruptions for a five-year period.
11. Ontario Hydro should begin actively promoting the sale of more interruptible power in 1979, with the aim of selling a further 100 contracted MW of both Class-1 and Class-2 interruptible power in each of the years 1980 to 1982, in order to provide the system with approximately 300 effective MW of interruptible power Class 1 as ready reserve and 500 effective MW of interruptible power Class 2 as slow-pickup reserve by 1982. Furthermore, if actual firm demand in 1976 and 1977 should significantly exceed the forecasts, consideration should should be given to advancing active promotion of further sales of interruptible power.
12. The formulae shown in Appendix V should be adopted for establishing a fixed discount for interruptible power, but the capacity component of the discount should be based on the annualized cost of capacity as determined by the marginal-cost study: that is, the generating-plant component of the demand charge.
13. Beginning in 1979, all potential customers for interruptible power should be offered interruptible power Class 1 and Class 2 at a fixed discount off the firm-power demand rate before the start of a calendar year; and any interruptible supply not sold then should be offered to customers through an open-market choice process.
14. The open-market choice (auction) of interruptible power should be conducted as described in this study, with all the constraints and clauses as there specified.

II. WHAT IS INTERRUPTIBLE POWER?

This section defines interruptible power, explains its role within the power system, provides the justification for treating interruptible power differently from firm power, and describes the value of interruptible power to Ontario Hydro and Ontario industry.

A. DEFINITION

Interruptible or curtailable power may be defined as electric service of lower reliability than firm-power service, in that it may be interrupted during conditions of system emergency (defined as inadequate total capacity, inadequate energy capability, and inadequate operating-reserves), in order to maintain a high degree of reliability of service supply to users of firm power.

Ontario Hydro presently offers for sale two types of interruptible power, designated as Class A and Class B, and two types of scheduled power, designated as Class C and Valley-Hour. Appendix I describes these classes.

B. VALUE OF INTERRUPTIBLE POWER TO ONTARIO HYDRO

Because it may be interrupted, this type of power enables Ontario Hydro to reduce the amount of peak generation capacity it would otherwise need to provide. Therefore, interruptible power is offered at a discount off the firm demand (kW) rates. To understand the role and value of interruptible power more clearly, one must understand the planning concepts for its supply.

1. Planning-Concepts for Supply of Interruptible Power

a. Load Forecasts

In load forecasting, estimates of firm load are reached by subtracting the estimated load reduction that cutting all interruptible loads would achieve, from the total estimated primary load.

The estimate of how much interruptible load reduction can be achieved is based on the difference between the total loads of the interruptible customers at the time of the system peak in December and the firm portion of their contracts. Ontario Hydro has been making such calculations for more than ten years, and the resulting amount of available interruptible load reduction comes to about two thirds of the sum of the customers' non-coincident interruptible loads. It has therefore been assumed that on the average, about two thirds of the total contracted interruptible load is available for cutting at the time of the system peaks.

However, experience in the past few years suggests that translating non-coincident interruptible load into potential capacity savings from load cuts required allowing for diminishing effectiveness of successive increments of interruptible load. For example, the actual amount of load available for interruption at the time of the December peaks on the East System in 1972, 1973, 1974, and 1975 were 56.4, 68.0, 60.0, and 58.7 per cent respectively, compared with the ten-year average of 66 percent. *It should be noted that this refers to actual maximum loads and not contracted amounts.* The amount available for cutting would, on the average, be a smaller percentage of the sum of the contracted loads. The actual interruptible load available for cutting at the time of the December system peak in 1975 was only thirty per cent of the sum of contracted interruptible demands, compared with 58.7 per cent of the sum of non-coincident interruptible loads.

Interruptible load forecasting is subject to oscillation and uncertainty due to factors like business cycle fluctuations. Most interruptible customers are large industrial firms, and their daily and weekly load shapes, as well as their overall level of demand, are likely to vary with overall business conditions and with changes in rates or pricing philosophy that may shift peaks. Therefore, customers' patterns of interruptible load may in future differ quite considerably from past ones.

b. System Planning

From a system planning viewpoint, there is no difference between interruptible power Class A and Class B, since both these classes are excluded from the planning-requirements for peak generation resources. Interruptible load is considered as supplied from the system's reserve generating capacity. However, the energy sales are included for determining the plant mix in the process of generation planning. In planning transmission and transformation facilities, interruptible load is considered as firm load, since these facilities must be capable of supplying the total primary load. Nonetheless, interruptible load can be cut under local transmission or transformation emergencies.

It is hard to determine how much interruptible power should ideally be offered for sale. If interruptible power were supplied up to the limit of reserve capacity, and there were no reduction in firm load, then the entire planning process would have to be reviewed, because (for example), of the response time to cut load to maintain system security in cases of emergency. On the other hand, if the amount of further interruptible load under consideration was in the order of 200 to 300 megawatts, the effect on system planning could be slight depending on the amount of future generating-reserves.

Present customer commitments to receive interruptible power are short term. Interruptible power is therefore not as significant a factor in planning the system as it could be. If the planners knew exactly how much interruptible power would be available at the time of the system peak for each of several years, economies could be made in the generation construction program. If, for instance, it were known that 500 megawatts of firm load would be converted to interruptible in a certain year, and remain as interruptible for several years, then Ontario Hydro could consider postponing a generating-unit of the corresponding size for that time period.

c. Operations Planning

From the standpoint of operations, interruptible loads, constitute a form of available capacity, in that cutting the loads has the same effect on available reserve as increasing capacity. One important difference between the two is that whereas the system operator has precise information on the status of capacity, he does not know with the same precision how much interruptible load he has available for cutting at any moment. However, at the present time his knowledge is accurate enough for operating-purposes. The estimate of how much interruptible load is available for cutting is based in part on the previous month's experience. Individual interruptible loads at the time of the monthly peak are used as a guide.

There must be spare power capability available above the hourly system demand, to meet system requirements under the following conditions:

1. When generation is lost;
2. When system load is heavier than was forecast, owing to weather fluctuations and/or forecasting errors;
3. For second-contingency trouble, when the risk level is greater than normal.

This spare power capability is called 'system reserve'. 'Operating-reserve' is the spare capacity which can be made available and fully activated within ten minutes, without exceeding system limits or any limitations of equipment. Ontario Hydro maintains an operating-reserve equal to the largest single contingency loss plus the estimated amount by which the five-minute peak load will exceed the average daily load. The hourly requirement for operating-reserve consists of 50 per cent 'spinning reserve' and 50 per cent 'ready reserve'. Spinning reserve is spare capacity that is synchronized to the system and can be loaded in ten minutes. Ready reserve is capacity that is not synchronized to the system and can be obtained and loaded in ten minutes.

Interruptible load is treated as non-spinning reserve, to conform with the requirements of the Northeast Power-Coordinating Council (NPCC). Class-B interruptible load is part of the ready reserve, whereas Class-A load is part of 'slow pickup reserve'. This latter type of reserve is defined as the capacity which must be available for loading within thirty minutes, in an amount equal to half the second largest contingency loss on the system.

Interruptible A and B loads are not normally cut to sustain export sales. However, to protect the integrity of the entire grid system, or if the receiving party is in an emergency condition (reduced to half their normal operating-reserve), Class-B loads will be cut. At present, Class-B loads may be cut to effect daily economy savings. Examples of these savings are to avoid starting-up combustion turbine units, or using water in the most inefficient plants. Interruptible A loads are carried from all available resources, excluding capacity-type purchases from the interconnections, unless the Capacity Reservation Fee has been incurred for the supply of firm loads. Both A and B loads may be used to relieve local system troubles. Heavily scheduled weekend maintenance programs and high weekend load growth rates may cause future problems. Similarly, the load differentials between summer and winter are at present tending to become smaller when maintenance is taken into account. Under extreme conditions of forced outages of large energy-producing plants, interruptible loads could require cutting for as long as 14 hours a day every day of the week. At present, the probability of this occuring is low.

Interruptible power is used like firm power by large use customers while at the same time it forms part of Ontario Hydro's system reserve. In the latter role, it serves as insurance against a system failure so that sufficient spinning reserve will be available if another failure should occur. Without interruptible power, the system would need more generating-capacity.

2. Hypothetical Examples of Interruptible Use Within the System

Hypothetical examples may help to make the role of interruptible power service clear:

First, a brief example of outage probabilities will illustrate the underlying principles for calculating loss-of-load probability. Assume a two-unit utility with the characteristics given in the accompanying table.

	Generation Capacity	Probability of Forced Outage*	Availability of Unit
Unit 1	100 MW	.10	.90
Unit 2	200 MW	.05	.95

* Forced Outages can vary from blown fuses to major system faults.

Probabilities may now be calculated for the various levels of generation capacity that could be available, as in the following table.

Available Capacity	Probability Distribution of Available Capacity				
0 MW	.1	x	.05	=	.005
100 MW	.9	x	.05	=	.045
200 MW	.1	x	.95	=	.095
300 MW	.9	x	.95	=	.855
					1.000

Thus the probability that the hypothetical system will have generating-capacity of less than 200 MW is .045, or roughly one in twenty. A similar analysis, could be conducted to arrive at Ontario Hydro's present goal for system loss-of-load probability of one in 2,400, or reliability of 2,399 in 2,400.

To protect this level of system reliability, Ontario Hydro needs a certain level of system reserve and/or interruptible power.

A second example will illustrate the role and value of interruptible power within the total system.

The following brief description of the composition of system capacity will serve as an introduction to the hypothetical example.

SYSTEM CAPACITY = TOTAL INTERNAL GENERATION + FIRM POWER PURCHASES

TOTAL INTERNAL GENERATION = ON-LINE GENERATION + IDLE CAPACITY

ON-LINE GENERATION = EXPORTS + ONTARIO PRIMARY LOAD + SPINNING RESERVE ONTARIO PRIMARY LOAD = FIRM LOAD + INTERRUPTIBLE CLASS A & B LOADS

IDLE CAPACITY = UNITS OUT ON PLANNED MAINTENANCE + NON-INTERRUPTIBLE READY RESERVE + NON-INTERRUPTIBLE SLOW-PICKUP RESERVE + COLD RESERVE (SPARE UNITS)

SYSTEM RESERVE = OPERATING-RESERVE + SLOW-PICKUP RESERVE + COLD RESERVE

OPERATING-RESERVE = SPINNING RESERVE + READY RESERVE

The level of system reserve is what determines the loss of firm load probability. With the foregoing relationships, assume that a hypothetical system peak appears as in the accompanying figure.

The role of interruptible power as ready and slow-pickup reserve for an electric utility should be evident. Increasing supplies of interruptible power would make more ready and slow-pickup reserve available. If the total system reserve level, and thus the loss-of-load probability, should remain unchanged, then a utility would need to maintain less cold reserve. Without interruptible power, more generating-capacity would be needed to supply the additional firm load, and so would more reserve capacity to maintain the reliability of the increased firm load.

The lower generation capacity required owing to interruptible supplies means that money savings will accrue to the Corporation. While there are differing methods of calculating the dollar value of these savings, it is generally agreed that they can be substantial in magnitude. These cost savings are the value to Ontario Hydro of supplying interruptible power.

(1) System Capacity MW	(2) On Line Generation MW	(3) Ties (Interconnections) MW	(4) Firm Load MW	(5) Int. Class A & B Load MW	(6) Spinning Reserve MW	(7) Idle Capacity MW
17,500	15,000	0	14,000	750	250	2,500

Note: (1) = (2) + (7) and; (2) + (3) = (4) + (5) + (6)

Now, assume that the system loses a 500 MW unit. The immediate result is:

17,000	14,500	500	14,000	750	250	2,500

Within ten minutes spinning reserve and the interruptible B portion of ready reserve will restore the ties as follows:

17,000	14,500	0	14,000	500	0	2,500

At the same time the non-synchronized portion of ready reserve will be loaded to restore spinning reserve as follows:

17,000	14,750	0	14,000	500	250	2,250

Assume that at this time the system looses another 500 MW unit. The ties are required once more.

(1)	(2)	(3)	(4)	(5)	(6)	(7)
16,500	14,250	500	14,000	500	250	2,250

At this point, the interruptible A load out of slow-pickup reserve will be used to restore the ties as follows:

16,500	14,250	0	14,000	0	250	2,250

As soon as additional units are available from idle capacity the system load will be restored as follows:

16,500	15,000	0	14,000	750	250	1,500

When the faulty generators are repaired the system is restored to its original conditions:

17,500	15,000	0	14,000	750	250	2,500

3. Long-Run and Short-Run Benefits of Supplying Interruptible Power

In the long run, selling more interruptible power would save Ontario Hydro the cost of generation equal to the load which would otherwise be firm, plus the corresponding reserve margin needed to support this firm load.

The problem is determining what is an appropriate amount of interruptible power to make available. Under present conditions, it is hard to determine this level, because of lack of knowledge of the customers' valuation of the relative price-risk relationship between firm and interruptible power.

In attempting to estimate an ideal amount of interruptible power, one would have to consider several factors. First, it must be assumed that the system may be designed to serve any amount of interruptible power. Second, the actual market environment is less than ideal, in that not all customers have entry to the market. Furthermore, factors such as load growth and changing joint probabilities of interruption (i.e., frequency and duration) must be taken into account.

The value to the system and hence the justification for offering this class of service at reduced rates, depends firstly upon the right to interrupt. Also important is the effectiveness of the measure in terms of the amount of curtailable power available at any given time, and its response time.

One should recognize that, other things being equal, the more interruptible power sold, the higher the probability of cutting becomes. This also applies if the general level of system reserve is lowered.

Assuming a constant level of reliability, as larger-sized units are installed in the future, system reserve requirements will increase. Units of a larger size will also entail increasing the daily operating-reserve requirement, and therefore it should be desirable to sell more power capable of short-term interruption. However, with system reserves, substantially reduced cuts to interruptible customers would become much more frequent and prolonged; and that might reduce demand for the service, as the price-risk relationship of interruptible power became less favourable compared to that of firm power.

Without interruptible power, both planned system capacity and planned reserves would be higher. Hence, savings have been realized for all customers, based on deferred generation at the time of the forecast. Fixed charges today are lower than if all load had been forecast as firm. Thus there are savings from having interruptible load whether cuts are made or not.

If excess generating-capacity exists, the reliability of interruptible power should be relatively high. This could provide an incentive for firm-power customers to convert to interruptible power, temporarily, in order to gain short term cost benefits. They might tend, too, to convert back to firm power once the surplus decreased, and the risk of interruptions increased, to the point where interruptible power was no longer attractive.

To let this happen would cause serious problems.

1. It would result in lost revenue, if the conversions were allowed to take place after firm rates and interruptible discounts had been approved for the year in question. If the conversions were known before the rates were set, the reduction in revenue from short-term conversions would require a corresponding increase in revenue from the remaining firm and interruptible loads.
2. It would give a false impression of the future volume of interruptible sales for planning-purposes.
3. It would provide an unwarranted short run improvement in reliability to the remaining firm loads.
4. No actual savings in future fixed costs would result as customers switched back to firm power.

The key point is that savings to all customers will occur only if the load forecast recognizes the amount of bona fide interruptible load in time to incorporate it into system-expansion plans. Savings in generating-capacity not installed are attributable to those customers who committed themselves to interruptible power in an earlier planning-period, and have no direct connection with the loads that actually materialize. Therefore it is recommended that

> ***In 1978 Ontario Hydro should base its fixed discounts for interruptible power on a fixed sum of dollars, based on deferred generation planned in 1973 and the forecasted billing kW for 1978 according to the official load forecast for that year.***

4. Generating-Capacity Saving

These are savings from reducing the generating-capacity required. They exist because of Ontario Hydro's right to curtail the supply of interruptible power. The value of interruptible loads arising from the possibility of reducing peak generation is hard to assess. First, there is the problem of determining the exact potential savings in kilowatts of peak generation corresponding to each kilowatt of interruptible load. Factors such as the following must be taken into account:

1. Diversity among the interruptible loads, and the diminishing effectiveness of successive increments of interruptible load sold.
2. During cuts, the customer is allowed a tolerance of five per cent on the cutting floor without penalty.
3. Customers are allowed to convert from interruptible to firm power on short notice.
4. Further administrative costs, system losses, and the savings in generating reserves that would result from the load's being interruptible rather than firm.

Another problem lies in determining the saving in system generation cost, assuming that the effect of cutting interruptible loads is accurately known. If part of the present interruptible load is converted to firm load, and/or part of the potential new interruptible load comes on the system as firm load, there would be an increase in future firm load. The resulting increased system costs could be used as a guide to the system saving associated with the load's being interruptible instead of firm. Small changes from conversions of interruptible or new firm load may produce no significant change in the generation program. But large changes (amounting to from one half to the full size of future units) can lead to advancing the planned in-service dates of new units. Today interruptible load available for cutting at time of system peak is in the order of 300 to 500 megawatts. If this load had been firm, Ontario Hydro would have required an additional 500-megawatt unit.

The chief use of interruptible power is to reduce peak load at times of system emergency. It follows then that Ontario Hydro should relate the value of interruptible power loads to the cost of the marginal plant or peaking-capacity along with an allowance for additional requirements for reserve generation.

Since both Class-A and Class-B interruptible power serve the same function at times of system emergency, both contribute equally to the savings in generating-capacity.

5. Operating-Savings

a. Class-A Interruptible Loads.

At present, from an operating-standpoint, the value of Class-A interruptible loads to the day-to-day operation of the system is small. This is due to three factors: protection by Class-B loads, which are cut first; protection by sales to interconnected systems (export sales being cut before interruptible loads); and the size of the present reserve margin.

b. Class-B Interruptible Loads.

Besides savings in generating capacity, this class of interruptible power provides annual operating savings consisting of two parts:

1. *Operating-Reserve Savings*

Even without load cuts, Class-B loads can effect savings by reducing the generation held as daily operating-reserve: that is to say, interruptible B loads are part of the reserve available to the system and capable of being fully activated within ten minutes.

The high load plateau on the system lasts roughly between 10 and 14 hours. For the rest of the time, hydraulic capability and partly loaded steam units provide all the required reserve. Class-B loads are therefore useful mainly during the peak period. For 1977 the value of Class-B interruptible power for this purpose has been estimated at about $220,000, as is shown in Appendix II; in future years this could rise to some $500,000.

2. *Differential Energy-Production Costs (Economy Savings)*

Daily economy savings from using interruptible B power, associated with not starting up combustion turbines at heavy load periods or not using water in the less efficient hydraulic plants, were estimated at about $3,500 for 1975 (see Appendix III). Since this amount is insignificant, and the practice increases the risk to the customers, it is recommended that

> *In 1978 Ontario Hydro should discontinue the use of interruptible power Class B to effect daily economy savings.*

On the other hand, using Class-B power as spare-capacity 'ready' reserve, which makes up part of the daily operating-reserve, could yield significant savings to the system and Ontario Hydro should continue to use Class-B power this way. Therefore it is recommended that

> *Ontario Hydro should make available to its large-use customers two types of capacity interruptible power: one, designated Class 1, with a higher risk, to be used as ready reserve as well as for system emergencies; and the second, designated Class 2, with a lower risk, to be used for system emergency conditions only, subject to thirty minutes' notice to conform with system requirements for slow-pickup reserve.*

C. VALUE OF INTERRUPTIBLE POWER TO ONTARIO INDUSTRY

Users of interruptible power today enjoy cost savings with little or no risk. The savings can amount to between ten and sixteen per cent of the firm demand charge depending upon supply voltage and load factor.

1. Customer's Decision to Purchase and his Price-Risk Tradeoff

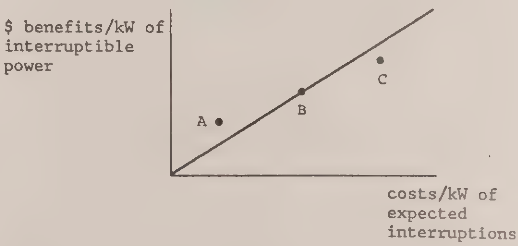
Firm power provides electrical service at a certain cost with a high degree of reliability. Interruptible power, however, provides electrical service at a lower cost, but with a greater chance of curtailments in service. An efficient use of interruptible service would ideally present users with a service that had definite characteristics of cost savings and risk attached to it.

A customer's demand for interruptible service is probably more price elastic than for the more necessary firm power. Use of interruptible power depends on a tradeoff between savings incurred and the cost of the additional risk of taking the service. However, this trade-off does not exist for the firm power user. As such, relative to interruptible, firm power is price insensitive. This is not to say that firm demand for electricity is insensitive to relative prices of other energy sources.

A customer probably bases his decision to take interruptible power on a quantitative cost-benefit analysis of the service. The costs result from the expected interruptions and lost production. The benefits are the dollar savings incurred through taking interruptible rather than firm power. Clearly, if the anticipated benefits outweigh the expected costs, the potential customer should purchase interruptible power. If the reliability of interruptible power decreases, the expected interruption costs will rise, and the customer could require a larger discount. An increase in the discount the customer faces means greater dollar savings. Given those, the customer may find he can profitably withstand a lower level of reliability for interruptible power: that is, higher expected costs of interruptions.

The only external factors any customer needs to make a cost-benefit calculation are expected joint probabilities of the frequency and duration of interruptions. Once the customer has this information he can develop a cost-benefit decision curve. Figure 1 shows a hypothetical curve.

Figure 1



The vertical axis represents the savings the customer can make by using interruptible power. The horizontal axis represents the costs per unit of expected curtailments. Costs will vary with each customer, according to his equipment and operations. The figure shows a zero intercept on both axes; but even if other intercepts are encountered, the analysis is still applicable.

The cost-benefit curve represents those points where the benefits of purchasing interruptible power exactly offset the costs of the expected interruptions. For example, at point B in Figure 1, the benefits and costs of using interruptible power would be equal.

At any point above the line, such as A, the benefits, or savings, from using interruptible power are greater than the costs. At

Point C, on the other hand, just the opposite would be true: that is, the costs are greater than the benefits.

The savings per kW as represented on the vertical axis are independent of the quantity of interruptible power taken. However, on the horizontal axis, the cost per kilowatt of expected interruptions may be influenced by considerations of amount. Inasmuch as taking more interruptible power, as against other sources of energy, will increase a firm's dependence on interruptible power the cost per kilowatt may fluctuate. More importantly, the cost per kilowatt of expected interruptions will vary with a company's ability to withstand varying frequency and duration of curtailment. For example, cost at B may represent one interruption of ten hours duration, while the cost at C may represent five interruptions of 30 minutes' duration. Clearly, this company is more affected by frequency than duration. The horizontal axis can reflect the cost per kilowatt of every possible combination of frequency and duration.

It is not necessary for the cost-benefit curve to slope upwards at a constant rate. A firm could have a curve wherein, as frequency and duration of interruptions increase, costs increase at a more rapid rate.

Conversely, the cost-benefit curve may represent a firm which, after some expected cost of interruption, has marginally decreasing costs.

A potential customer will only consider interruptible power if the savings from its use offset the costs of expected interruptions. The savings per kilowatt are a function of the discount per kilowatt that a company acquires. The costs are mainly related to the degree of reliability of interruptible service.

Figure 2

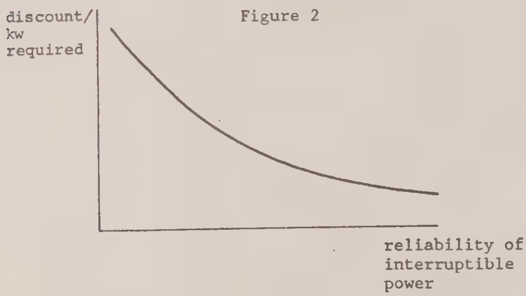


Figure 2 shows the relationship between discount per kilowatt a customer requires (in order to have a positive cost-benefit relationship) and the reliability of interruptible service. The relationship may be stated as follows:

> *The lower the degree of reliability of interruptible power, the higher the expected costs per kilowatt of interruption, and thus the higher the discount per kilowatt required by any company.*

In the limit, as the degree of reliability of interruptible power approaches that of firm power, the discount per kilowatt any company required in order to cover expected interruption costs should move towards zero.

Companies will implicitly or explicitly perform a cost-benefit analysis on every good or service they intend to purchase or utilize. This approach ensures efficient use of resources. A company will hesitate to purchase any good or service for which a cost-benefit or cost-effectiveness analysis cannot be carried out.

Thus in order to increase the long-run use of interruptible service, to the benefit of both Ontario Hydro and its customers, its characteristics must be clearly distinguished from those of firm power. The proposed pricing-system, discussed in Section IV, along with projected probabilities of interruption, will, provide industry with a clearer view of the benefits and costs of taking interruptible power.

2. Uses and Markets for Interruptible Power

Ontario Hydro has several energy-intensive customers, each of which could economically withstand a different degree and frequency of interruption. For example, arc furnaces could probably withstand many short interruptions, whereas air-separation liquifiers could operate economically with fewer but longer duration curtailments. Most of the energy-intensive industries that could make use of interruptible would vary between these two extremes.

There are many industrial operations where full or partial reduction of load can be accomplished without damaging equipment or material in process. Where electricity is a relatively high cost factor, and the product or material in process can be stored, these operations are candidates for interruptible power.

Those customers whose cost of power is only a very small share of their overall production costs may not be in the market for interruptible power. This is because the savings in power costs are less than the additional costs associated with breaks in production from loss of power supply. It simply becomes a trade-off against firm power, which has a high reliability.

On the average in Ontario, electricity accounts for about 2 to 3 per cent of value added in manufacturing-costs. The most electrically intensive industries are abrasives and electrochemicals. Heavy users of electricity seem to find it worthwhile to make their processes flexible, so that they can take advantage of electricity with lower service continuity, and consequently lower price. They obtain this flexibility by such means as intermediate stockpiling.

One might assume that an electrically intensive industry such as abrasives could schedule its furnace-loading so as to take advantage of a high load-factor and off-peak power. However, in this industry the process lasts more than 15 hours from start to finish, whereas the proposed off-peak period covers only the eight nighttime hours from 11:00 p.m. to 7:00 a.m. Therefore, scheduling of furnaces to make use only of the off-peak period is unrealistic on a continuous basis.

On the other hand, in the manufacture of silicone carbide the furnaces may be interrupted for some time without harming the product. These interruptible furnace loads can therefore be used to regulate the overall power demand of the plant, and so obtain high load factors and in turn lower the per-unit costs.

The manufacture of liquid oxygen and nitrogen, is a good example of a process adaptable to interruptible service. Using electric power and air as raw materials, air-separation plants purify and liquify air for separation, by distillation, into its chief components, oxygen, nitrogen, and argon. A manufacturer may take as much as 75 or 80 per cent of his electricity as interruptible power. Interruption shuts down the refrigerating-equipment (little notice required), and there is no output. Once full power is restored, the refrigerating-unit needs one or two hours' use of power before production can be resumed.

Appendix VI of this section examines the applicability of interruptible power and the effect of interruptions for five separate industrial processes. On the basis of 30 interruptions a year, with an average duration of five hour for each interruption, the value of lost production, in 1975 dollars per kilowatt per year, ranges from $25.60 to $73.60.

Using the raw data from this appendix, one can recalculate the value of lost production in terms of Ontario Hydro's experience in the year with the greatest number of interruptible hours cut during the past eight years. In 1968, there were 18 cuts, with an average duration of 1.78 hours per cut. These same figures are used for a simulation within Part 2 of Appendix IV, resulting in a value of lost production, in dollars per kilowatt per year, ranging from $9.87 to $22.85. These figures make interruptible power feasible, because discounts for its use could foreseeably surpass these per-kilowatt costs. This example shows the applicability of interruptible power, its potential financial attractiveness, and its effect upon industry.

III. CONDITIONS FOR INTERRUPTIBLE AND SCHEDULED POWER SUPPLY

Ontario Hydro currently has 29 interruptible contracts in force (which are generally both firm and interruptible) representing the following loads:

Type of Contract	Number of Contracts	Contracted Kilowatts Interruptible	Contracted Kilowatts Firm
A	20	528,000	93,000
B	5	118,000	30,000
A & B combined	4	118,000	37,000
TOTALS	29	764,000	160,000

The actual interruptible load accounts for about 22 per cent of the total of all direct industrial customers' loads, and the contracted total of 764 megawatts for Classes A and B together constitutes about five per cent of the system's annual winter peak. The 764 megawatts is an increase of 121 megawatts over 1975.

The amount of cuts of interruptible A and B power for 1968 to 1975 inclusive is shown in the following tables.

Interruptible A

Year	No of Cuts	Actual No of Hrs Cut	Permissible No of Cut Hours	Actual Cut as a Percentage of Permissible
1968	18	32	1295	2.6
1969	9	22	"	1.6
1970	1	3	"	0.2
1971	4	5	"	0.3
1972	0	0	"	0
1973	0	0	"	0
1974	0	0	"	0
1975	0	0	"	0

Interruptible B

Year	No of Cuts	Actual No of Hrs Cut	Permissible No of Cut Hours	Actual Cut as a Percentage of Permissible
1968	73	240	1314	18.2
1969	84	230	"	17.5
1970	42	109	"	8.2
1971	25	70	"	5.3
1972	6	12	"	0.9
1973	6	11	"	0.8
1974	4	8	"	0.6
1975	2	1	"	0.1

Cuts are defined as group coincident cuts; they are not individual customer cuts, and no distinction is made between 60-Hertz and 25-Hertz loads.

The right-hand column in the table shows the duration of cuts as a percentage of the maximum allowable hours of interruption as specified in the conditions of service. The steady downward trend indicates both low frequency and short duration, resulting from increased amounts of reserve capacity.

Because available resources have been adequate, Class-A loads have not been cut during the last four years. During the same period, Class-B loads have been cut very seldom, due in part to the favourable situation of export sales. When a loss of generation occurs in Ontario Hydro's system, the present practice is to withdraw export sales rather than cut interruptible B loads, unless the foreign system is experiencing emergency conditions. As future generation reserves become relatively lower, interruptions will become more frequent.

A. CONTRACTUAL LIMITS

1. Minimum Interruptible Contract Amount

The present minimum of 5,000 kilowatts for interruptible power contracts was chosen primarily because of problems with giving notice to cut load, administrative costs, and the need to be able to interrupt fairly large blocks of power when required. A questionnaire on interruptible power (sent to all direct industrial customers in October 1975, to gather information for this study) showed that of the 22 large companies for whom interruptible use is feasible, 8 would welcome a lower minimum. Reducing the size of the minimum block would no doubt increase the number of interruptible users. However, an important factor is the problem of notification by telephone. The lower the minimum amount, the greater the number of customers that have to be notified to make the required cut in load. If Ontario Hydro could introduce a more automatic procedure for cutting loads (such as a signal from the control centre), then perhaps the 5,000-kilowatt level could be lowered. In the mean time, it is recommended that

The 5000-kilowatt minimum contract amount should be retained until such time as some more practical form of notification of load cutting and measurement can be implemented.

2. Availability of Interruptible Load When Required

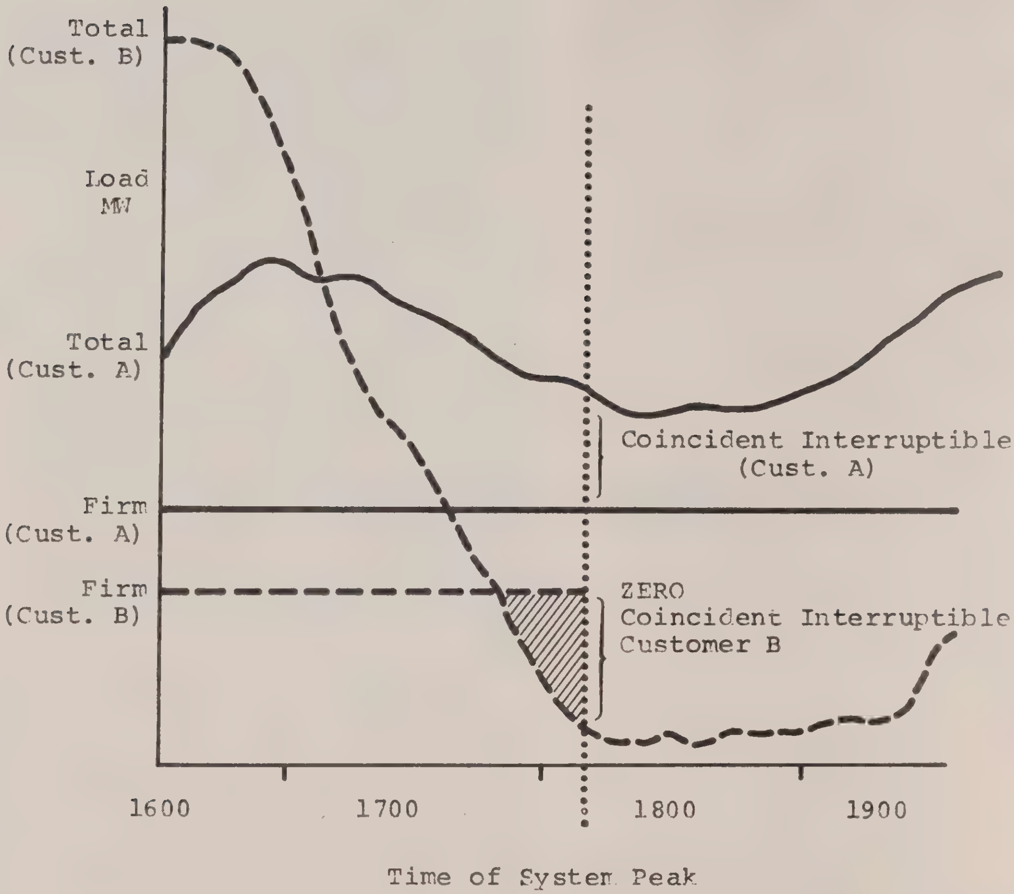
Most customers taking interruptible power also take firm power. For present billing and operating-purposes, firm load is considered to be fully taken before the customer takes interruptible load; that is, interruptible load is 'floated' on top of the firm load normally carried. The customer is not penalized, as long as he cuts load, on request, to the 'cutting floor level', 5 per cent above contracted firm demand.

Industrial practices such as single-shift operations may leave a plant with total demand lower than the interruptible contract amount at the time of the daily peak. This condition, as illustrated in Figure 3, shows that interruptible customers cannot always be relied upon to have their contract demands available for cutting at times of maximum system load.

Availability has been reviewed with a view to requiring interruptible customers, through contract conditions, to guarantee to cut some minimum amount of load on request. The problem with assuring interruptible capability is that either the customer's total load must exceed the firm contract demand by the guaranteed amount at the time of system stress, or else the customer must cut a portion of the firm load. However, this problem of guaranteeing or assuring interruptibility is somewhat illusory, since any load the customer is not using has already reduced system load

Figure 3

INTERRUPTIBLE LOAD COINCIDENT WITH SYSTEM PEAK
AN EXAMPLE OF THE PROBLEM



Net Coincident Interruptible ⟶ 0
Net Coincident Firm < Sum of Firm

or is being used elsewhere in the system. There is, therefore, little justification for cutting any portion of the customer's firm load until all other reserves and contingencies have been applied. This is not to imply that a customer would not have to guarantee to cut any interruptible load above firm. In practice load is usually shed in discrete blocks; and for any given customer, this could lead to a remaining level of load slightly above or below the firm-contract amount.

It could happen that, no matter whether a customer was at, below, or slightly above contracted firm demand, some of his load would be part or all of the manufacturing or industrial process designated as the interruptible load. For example, a customer with a contracted firm demand of (say) 30,000 kilowatts and a contracted interruptible demand of (say) 10,000 kilowatts might, when asked to cut, be using all 10,000 kilowatts of load designated as interruptible, but only 19,000 kilowatts of firm power. If so, the load would appear as 29,000 kilowatts (1,000 kilowatts below firm) and the customer would not incur any penalty for not cutting the interruptible type of load he was using.

One solution explored to solve the problem of identifying interruptible loads was to require separate switching and/or metering for them. In practice this might not prove possible for some interruptible loads, and it could involve a cost disadvantage (the cost, for instance, of protective switchgear apparatus and metering circuits). However, it might prove feasible where the customer had two or more major and distinct processes in one plant, such as melting (by electric furnace) and milling. The proposal would not, of course, guarantee that load would be available for cutting at the time of need. Nevertheless, it could provide factual levels of interruptible loads for purposes of billing and contract, and do away with the need to specify the 5-per cent cutting floor level in the contracts.

For the total interruptible load of the system, the problem of availability when required may not be that serious, given that, on the average, coincident demand for interruptible load may remain relatively constant.

Nonetheless, the problem still remains of identifying the customers using interruptible load at the time of system need. An automatic transmittal system for load information, such as telemetering of total loads, could ensure accurate measurement of interruptible load when required. This would be a simple telemetering circuit that would read each customer's total load, subtract the firm contract amount, and provide the system control centre with precise instantaneous data on the total amount of interruptible power available for cutting. The control centre could also give the customers a signal to shed load over the same carrier lines. In view of the anticipated increased use of interruptible power and increasing probability of interrupting such loads, it is recommended that

> *An automatic load information transmittal system, such as telemetering, should be installed to provide the system control centre with totalized load data for all interruptible customer loads.*

3. Exit from and Entry into Interruptible Contracts

At present customers taking interruptible power are allowed to switch to firm power on relatively short notice. This action compares unfavourably with the much longer six to ten year period that Ontario Hydro needs to install new generation facilities. Hence it has been argued that in practice no generation savings can be assured under these conditions. Yet, the customers get the benefit of the full discount allowed. This could affect long-range planning and short-run system operations if a large percentage of customers were to switch to firm power. However, a switch of one or two customers might have little effect, and would reduce the reliability and price of firm load only slightly.

On the other hand, if an existing firm load were to be converted to interruptible, it could be to Ontario Hydro's advantage in the long run. If the changeover took place when future generating-reserves were forecast to be low, it would offer an improvement in reliability to remaining firm customers. But until the generation program was adjusted to reflect the reduction in firm load, no system savings in fixed costs would arise, and the reduction in revenue from the conversion would require a corresponding increase in revenue from the remaining firm loads. Ontario Hydro has nothing to gain from letting customers switch back and forth between firm and interruptible loads. As energy comes to account for a larger share of total manufacturing-costs, it is not unreasonable to expect industries to attempt such action as a way to minimize their costs. It could be undertaken to coincide with movements in the Ontario business cycle.

Since interruptible power provides generation capacity savings due to its function as reserve against a major contingency failure, some continuity and consistency is needed in contracts for purposes of future planning. A situation where customers move in and out of interruptible and firm contracts distorts planning and policy decisions. Hence it has been suggested that customers taking interruptible power should have to sign a contract that prohibits switching to firm power for a period of as long as ten years. That, though, would introduce undue rigidity and constraint into the interruptible market and might needlessly discourage taking the service. It would be better to draw up the contracts to take account of both the customers' preferences and the time period required to plan, design, and construct adequate firm load generation capacity. This would help discourage customers from short-run, expedient switching from firm to interruptible power and back again to satisfy their own preferences.

One consideration in arriving at an appropriate period of commitment for interruptible contracts is the current procedure for taking on new firm load. At present, Ontario Hydro will accept new firm load with shorter notice than it needs in order to install new generating-facilities. If transformation and transmission capacity is available, and depending on the construction period of the industrial plant, the notice may be as short as two to five years. Another consideration is that peaking-capacity to supply load converted from interruptible to firm could be installed in much less than ten years.

To ensure a consistent treatment of customers that wish to switch from interruptible to firm load, and customers contracting for new firm load, it would be inappropriate to hold contracts for interruptible power to the lead time needed to install new generating-plant. Nevertheless, it would be equally unwise to offer a discount for interruptible use that did not provide the utility with long-term savings in generating capacity. Every effort should therefore be made to encourage longer-term commitments to interruptible power, and customers taking it should be held responsible for the costs incurred if they switch to firm-power and thereby impair service to other firm power customers.

On balance, it is concluded that a five-year commitment would provide adequate stability to the planning-process and ensure real savings in future fixed charges. While customers would be

allowed to switch back to firm load, the contract for interruptible power ought to require that under system emergency conditions which necessitated cutting firm load, those customers that had left the interruptible market, without providing five years' notice, would receive cuts ahead of other firm load for a term of five years. The amount of load subject to cutting could be equated to the customer's maximum interruptible load in the previous five-year period (in other words, lagged five years). Furthermore, any such customer that failed to cut load on request should incur a surcharge of 50 per cent on the firm demand rate, applied to the amount of load designated as interruptible.

Three possible orders of cuts in firm load were considered for customers who switched from interruptible to firm power:

1. Chronological order: that is, the most recent interruptible user first;
2. Cuts based on a fixed rotation sequence;
3. Cuts based on random number generation.

The first approach would ensure less risk of interruption for the customer, the further he moved beyond the date when he left the interruptible market. The second approach would distribute cuts in any given period equally among all designated customers. The third approach would simply let chance decide which customers' firm load were cut. The longer the time since a customer left the interruptible market, the likelier it is that capacity will cover his total load;therefore the first approach is the most logical. It is the only one to reflect the decreasing burden that a customer places on the system, the longer ago he left the interruptible market. For customers with the same date of leaving, the order of cuts should alternate on an equal basis. It is therefore recommended that

> ***Any customer that switches from interruptible to firm power, without providing five years' notice, should be subject to interruption during the next five years before any other firm customer if firm load cuts become necessary; and the amount of load subject to cutting should equal the customer's maximum interruptible load in the previous five years. In addition, the cutting order should be chronologically based: that is, those customers most recently having exited from interruptible power contracts should be cut ahead of other designated customers. Furthermore, failure to cut on request should result in a 50-per-cent surcharge on the firm demand rate applied to that amount of load designated as interruptible.***

This recommendation would provide Ontario Hydro with a tertiary reserve corresponding in any year to the sum of the effective amount of interruptible load subject to cutting that had been switched to firm power.

4. Length and Frequency of Interruptions

As was said in Section II, ocassionally, because of problems of energy or capacity shortage, it is possible that interruptions of as long as 14 hours could be required. From the standpoint of planning and operations, then, it would be better if all contracts for interruptible power were liable to interruptions of as long as 14 hours per day, seven days a week, throughout the year.

However, a single interruption lasting 14 hours would not be compatible with the requirements of all users of interruptible power. Various industries can stand varying degrees of interruption in terms of length, frequency, and notice time. For example, during the 1975 Hearing of the Energy Board, AMPCO submitted a brief that included the following statement:

> *The interruptible A and B power service provided by Ontario Hydro, exposes the industrial user to a potentially disastrous degree of interruptions in return for a very modest difference in power costs. Both forms would potentially expose the industrial plant to very long periods of unavailable power without a strict understanding of when the power supplier would actually call for curtailment. There are very few, if any, industrial plants who would find it economical at any price to withstand the upper limit of interruptions that are called for in the contracts. Therefore, the first impression given to a new industry is that the interruptible power schedule would expose them to a gambler's risk rather than a calculated business probability. Manufacturers have to deal with probability questions continuously, but generally are not interested in arrangements which would expose them to unreasonable risk such as the maximum features of Ontario Hydro's schedules.*

Industrial needs correspond fairly closely with Hydro's actual system operations, which can vary in terms of the requirements for length, frequency, and notice to customers. Since it will be desirable to encourage greater use of interruptible power in the future, it will be necessary to make a trade-off between what customers feel to be an unreasonable length for interruptions, and marketability of the product.

In view of these considerations and the small likelihood at present that 14-hour cuts would be required, it is recommended that

> ***Interruptible power contracts should provide for cutting five days a week, Monday to Friday, with maximum cuts of five hours per day during March to November inclusive and ten hours per day during December to February inclusive. In addition, maximum cuts of two per day, ten per cent of the hours in any month, and ten per cent of the hours in any year are recommended, subject to alteration as required to meet changes in system conditions.***

This recommendation is made taking full account of several factors that might seem to argue against it. These are

1. The observed flattening of daytime summer loads owing to air conditioning, which bears on the recommended cutting-limit of five hours a day in summer.
2. In contingency situations, the system can be caught short on weekends just as easily as on weekdays. This bears on the recommendation to confine cutting to weekdays.
3. At any time of the day or night, or of the year, local distribution problems may occur that entail cutting interruptible or even firm load.

However, the last clause of the recommendation will allow for changes based on experience with changing system conditions over time.

5. Practices of Other Utilities

The Tennessee Valley Authority's conditions for supplying interruptible power call for specified cumulative hours of interruption in the short and long term (ten years). The long-term guarantee lets customers plan production and invest in capital facilities on a basis of no excessive interruptions.

Interruptions can be quite severe, namely, as many as two a day, accumulating to daily and weekly totals of 12 and 48 hours respectively. Total annual interruptions are limited by contract

provisions to 600 hours (compared to Ontario Hydro's 1295 hours for class A and 1314 hours for B). Long-term cumulative interruption times are limited to 3 per cent in any ten years.

The Bonneville Power Administration (BPA) is primarily a hydraulic source, bulk-marketing agency for electricity in the U.S. Pacific Northwest. Its principal customers are utilities in the region, but it also serves several large direct industrial customers. Prices are offered for firm, non-firm, and interruptible power, based on discounts from the basic rate for high-load-factor non-seasonal customers.

Industrial customers of BPA buy about three quarters of their plant load under the modified firm rate, which is 5 cents per kilowatt per month lower than firm. Twenty-five per cent of this modified firm can be interrupted because of system outage or to protect firm-power customers. The rest of the power sold to industrial customers at 5 cents per kilowatt per month less than modified firm is liable to curtailment at any time. It would seem that the interruptible conditions BPA imposes are quite stringent, perhaps because the source of power is hydraulic and depends on good seasonal conditions. Rates for firm power were $1.20 per kilowatt per month at transmission voltage levels in 1974.

The British Columbia Hydro Authority makes no provision for interruptible discounts. However, it reserves the right to curtail service to all customers, at any time, during a shortage of water or fuel supply, whether actual or anticipated by officials of the Authority. Curtailments may also result from a breakdown or failure of generation, transmission, or distribution plant, lines, or equipment.

Customers may expect a utility to provide them with some predetermined maximum cumulative hours of interruption in contract conditions on a daily, weekly, monthly, yearly, and even longer-term basis. However, one must exercise some caution, because if the maximum cumulative hours were rapidly used up, then the customers would essentially be buying firm power at a discount for the rest of the period. It is then conceivable that a situation could arise where there would be no more interruptible power available for cutting during system emergencies, and other courses of corrective action would be required. For this reason, and considering the effect that cutbacks in the generation program would have on system reserves beyond 1978, guarantees of maximum cumulative hours of interruption beyond one year are not recommended for use by Ontario Hydro at this time. It is suggested, however, that this should be reviewed on a continuing basis.

6. Scheduled C and Valley-Hour Power

The present billing procedures for scheduled Class-C and Valley-Hour power provide a well-defined set of qualifications. The problem with the Class-C schedule of restricted hours is that the hours vary from month to month, and it is hard for customers to schedule production on this basis. In addition, Class-C customers need not cut load at times of system emergency, but rather cut it when they have agreed to.

Under a pricing-methodology incorporating time-of-use rates or peak-versus-off-peak pricing, the present conditions of supply would no longer be appropriate. For example, the five-hour restricted period for Class-C loads would not match the 16-hour daytime peak price period, and the eight-hour nighttime off-peak price period would match the current hours when valley-hour power is available. Hence there would no longer be a need for such a class of service.

For these reasons, and seeing that there are only two class C-customers, with a total non-coincident load of 12 megawatts, and no valley-hour power customers at all, it is recommended that

In 1978 Ontario Hydro should discontinue offering for sale both scheduled power Class C and Valley-Hour power, and the existing Class-C customers should be offered the choice of converting to either firm power or interruptible power Class 1 or Class 2.

7. Interruptible Power for Customers of Municipal Utilities

At present interruptible power is sold to industrial customers of municipal utilities under a three-party arrangement, with Ontario Hydro initiating the load cuts. Contractual conditions differ in that the minimum requirement is 10,000 kilowatts, which limits its use.

If municipal utilities were allowed to establish internal interruptible contracts and administer cutting privileges independently of Ontario Hydro, customer interruptions would be based on the needs of the municipal utility rather than those of Ontario Hydro. It is considered more appropriate for Ontario Hydro to initiate interruptions, to meet the requirements of the bulk-power system.

It may be argued that different rates and restrictions on use of interruptible power by industrial customers in the municipal utilities, compared with those of the Power District, lead to unfair competition. Since interruptible power yields the same savings in generation, whether supplied to customers of a municipal utility or of the Power District, there should be no differential in the discount offered. Therefore it is recommended that

Interruptible power should be made available to large-use customers of municipal utilities under the same terms and conditions that apply to Ontario Hydro customers.

B. SYSTEM PERFORMANCE AND VARIABILITY OF SUPPLY

1. System Demand and Energy Peaks

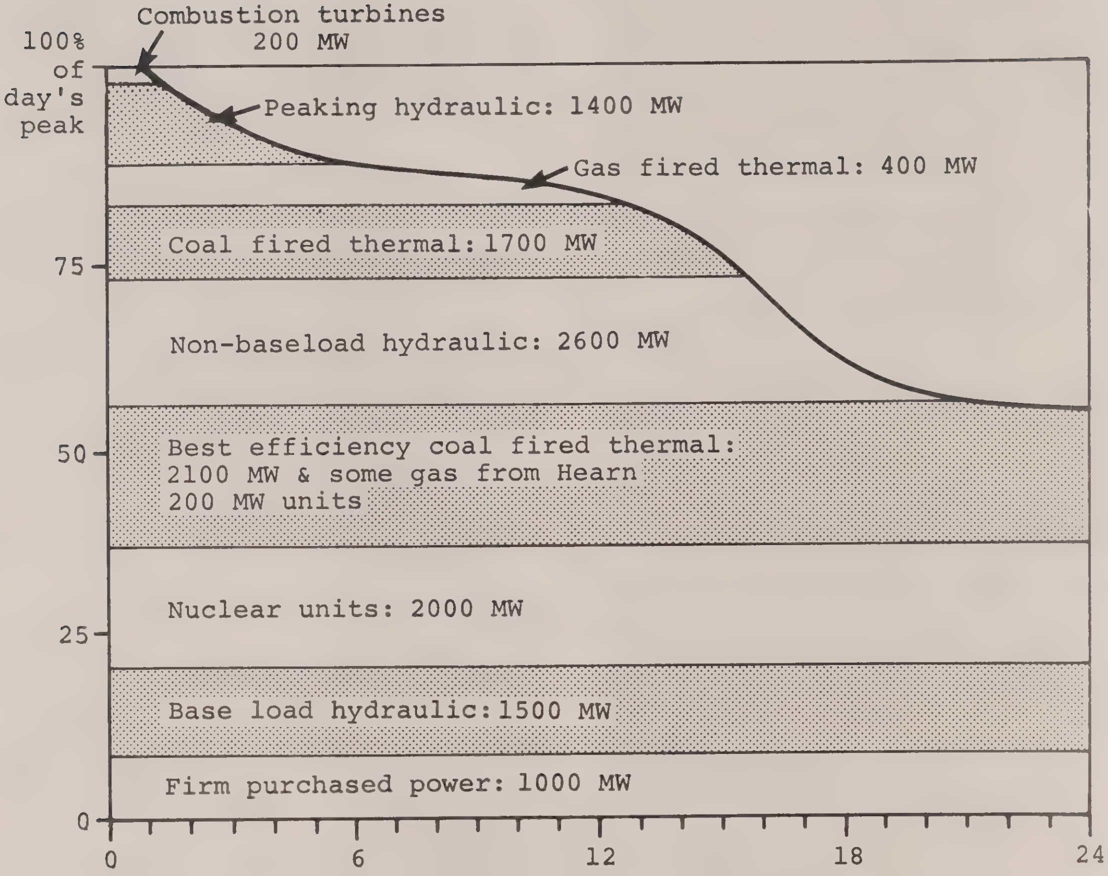
System Planning allows for interruptions to peak primary loads in its generation plant planning-process in that its designs are based on firm demand (that is, excluding interruptible power). Peak primary loads are carried by a mix of generation, as Figure 4 shows, including combustion turbines, peaking hydraulic units, and older, less efficient thermal plants, each with different cost characteristics.

It must be realized that one cannot assess the system's capability of supplying load at any time merely on the nameplate ratings of the generating-units. One has to take account of other factors, such as the following:

1. Variability of hydraulic units because of seasonal and year-to-year variations in river flows, and because the capacities of the units exceed the stored-energy capabilities of the headponds;
2. Limitations to the ambient temperatures of thermal units;
3. Energy-production capabilities (in average megawatts);
4. Equipment stress limits; and
5. Forced, planned, or maintenance outages, and occasional partial deratings of generating-units.

FIGURE 4

Ontario Hydro: Load Duration Curve
(High Winter Day)



Ref: Daily Load Summary: Operations Division

All these factors must be taken into account in attempting to calculate the amount of interruptible power that could technically be made available for efficient operation of the system.

2. Daily, Seasonal, and Weather Effects

A set of ten-year hourly statistics for the East System was studied. The data showed that there had been some filling of night valley hours. Results for typical winter and summer weekdays are shown on the accompanying two graphs.

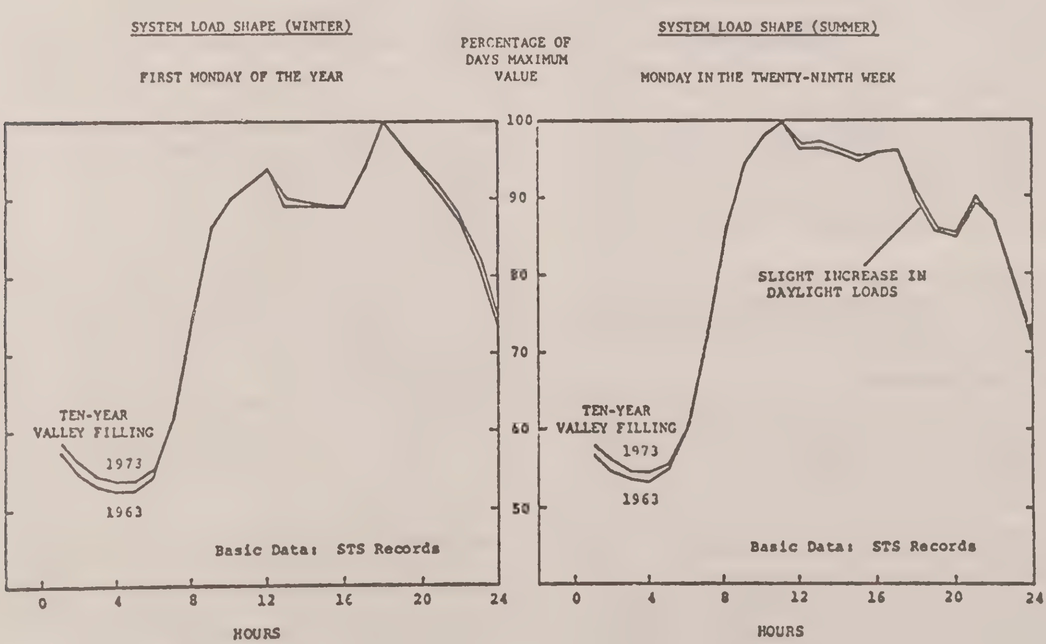
The graphs show roughly 1.5 per cent of night valley filling between 1963 and 1973. This means that, if the 1973 daily load curve had remained the same shape as in 1963, there would have been about 100 megawatts less valley-hour load than there actually was. The valley is typically about 30 per cent lower than the daytime plateau, which shows there is substantial room for customers who may have suffered interruptions during the daytime hours to fill the valley between 11 p.m. and 7 or 8 a.m., assuming they have to operate at night to meet their production schedules.

Seasonal and extreme weather effects were also studied. Briefly, the energy used during the lowest summer month in kilowatt-hours is about 80 per cent of that used during the highest winter month. The effect of extreme weather has been estimated as requiring an additional capacity of about 450 megawatts (under 1975 conditions) on an extremely cold winter's day of the type encountered once every ten years; this is of low probability and would have only a slight effect on generation requirements of the East System for interrupting load. However, this effect is estimated to be growing more rapidly than demand: that is, the system is becoming more sensitive to temperature, and under 1985 conditions the additional capacity needed could amount to some 1100 megawatts. Some of this weather-sensitive load could be traded off for an equivalent amount of interruptible power.

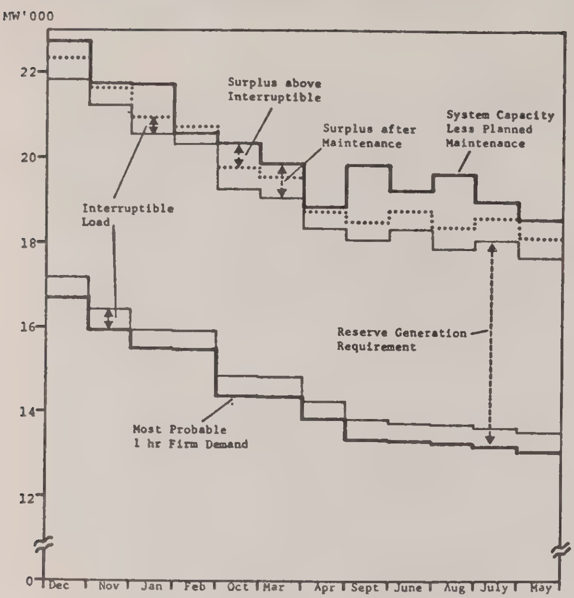
3. System Factors

Customers taking interruptible power are spread across the province, and emergency situations calling for reserve generation may at times be localized in the East System. When that is so, the network situation may preclude obtaining full benefits of interruptible load action for the needs of the bulk-power system.

The earliest use of interruptible load to save capacity in the Northwestern Region would be 1979, because generation is committed up to that date. The Northwestern situation was studied in 1969, 1971, and 1974, with virtually the same outcome. Even interruptions of as long as 16 hours every day for several weeks would only yield capacity savings after 1979. This is because of the high, very long, and flat load plateau, and the very high load factor, in the Northwestern Region. With new generation in the Northwestern Region postponed because of capital constraints, this situation will continue into the 1980s. The committed generation reserve on the East System to 1979 is maintaining a low need for interruptible load. However, without interruptible load, both generating-capacity and reserves would have had to be higher. Thus major savings have been realized, based on generation postponed at the time of the forecast. For illustrative purposes, short-term seasonal characteristics are shown in the accompanying diagram for the East System.



1978
ONTARIO HYDRO - EAST SYSTEM
MONTHLY LOAD, CAPACITY & RESERVE SITUATION



ILLUSTRATIVE BASED ON PRELIMINARY ESTIMATES - MARCH, 1976

The reserve generation requirement includes the capacity needed to cover expected outages and the amount set aside for system regulation: that is, the difference between momentary peak and the one-hour peak. It will be noted that there is considerable generation reserve remaining after planned maintenance and after supplying interruptible load in every month in 1978 except February. This would suggest that even during periods of heavy seasonal demands on the system, there is a low probability of load cutting in 1978. The longer-term situation for the month of December to 1984 in the next graph shows how a deficit (negative surplus) develops after the interruptible load is supplied.

This implies a much higher probability of cuts in interruptible power beginning in the winter of 1979. The amount of negative surplus indicates the amount of interruptible power that might be sold to improve firm customer reliability.

4. Load-Cutting Probabilities

Using interruptible power efficiently ought to leave the user facing a service that definitely had characteristics of cost savings and risk attached to it in the form of a joint probability distribution of the frequency and length of interruptions.

Power System Operations could provide such information, given some assumed capacity constraints and acceptable level of reliability for power supply to firm customers. Therefore it is recommended that

> *In offering interruptible power for sale, Ontario Hydro should provide the customer with estimates of the probabilities of interruption in terms of frequency and duration for a period of five years.*

This recommendation is made with the knowledge that at present the tools are not available for predicting the frequency and length of interruptions five years ahead of time with any confidence. Adopting the recommendation would entail undertaking the considerable task of developing the needed methodology, which ought to include probability of interruption from local system trouble (in transmission and distribution) as distinct from loss of system generation.

The auction approach to the sale of interruptible power, as discussed in Section IV, is contingent on having this information available. This is necessary if the customer is to be capable of determining the expected costs to him associated with various levels of risk. Without such data, the auction approach would be infeasible.

C. DETERMINING HOW MUCH INTERRUPTIBLE POWER TO MAKE AVAILABLE FOR SALE

Ontario Hydro's current criterion for availability of generation or supply is 99.96 per cent. This suggests there is one chance in 2,400 that supply will not be adequate to meet all system demands. If a system is to be reliable, it must have a positive reserve margin of generation over the expected peak demand. This results from an availability of major generating-units of less than 80 per cent. Some of the factors affecting their availability are:

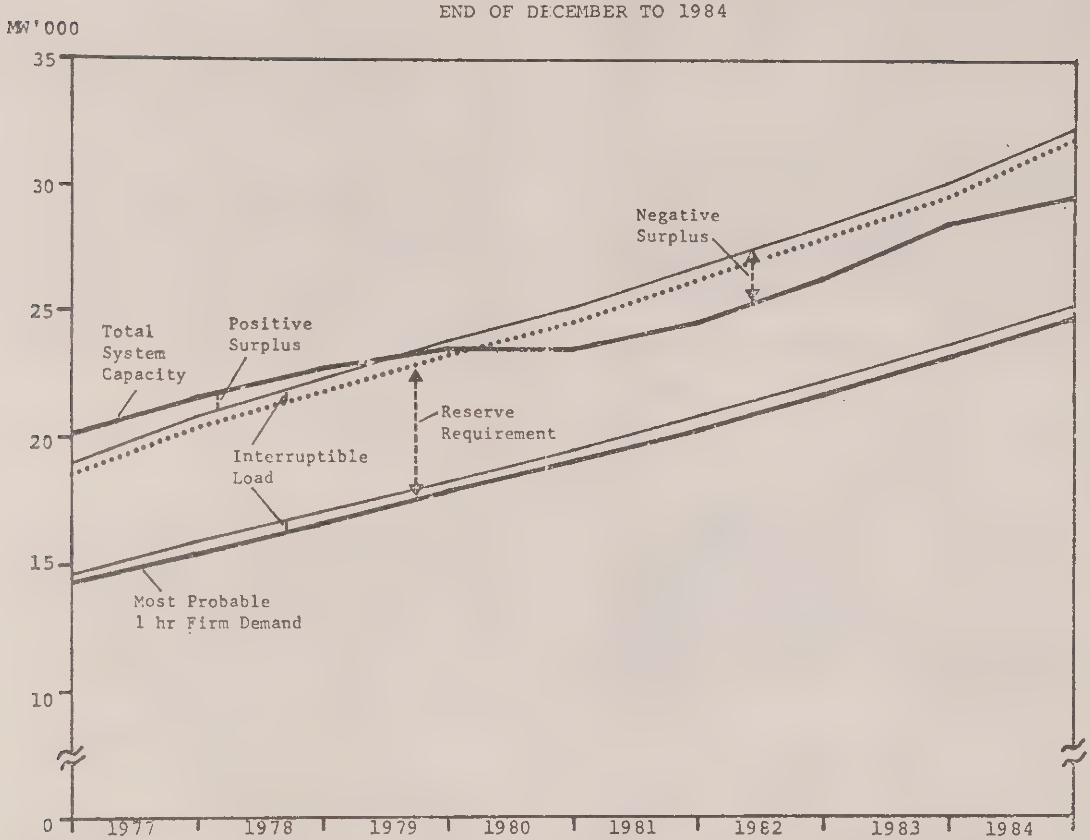
1. Periodic breakdown from wear and tear, inherent defects, bad weather, and similar causes;
2. Periodic preventive maintenance to reduce the incidence of breakdowns;
3. Failure of supply of essential materials such as fuel or heavy water;
4. Possibility of strikes;
5. Lags in construction schedules for new equipment; and
6. "Shakedown" problems with new equipment.

The reserve requirement is calculated on a computer program called Loss-of-Load Probability (LOLP). The LOLP varies from month to month and year to year, depending on the size and availability of the new units being added. It averages between 25 and 30 per cent of demand.

At all times, Ontario Hydro has to maintain operating-reserve equal to the largest single contingency loss plus the estimated amount by which the five-minute peak load will exceed the average load for the hour. Spinning Reserve must equal half the capacity of the largest single contingency, and Ready Reserve must equal the rest of the operating-reserve. On the Ontario Hydro system, the largest units at present are the 500-megawatt units at Lambton, Nanticoke, and Pickering; but units of 750 megawatts are scheduled for Bruce late in 1976. The estimated amount by which the five-minute peak load exceeds the average load for the hour varies from 50 to 150 megawatts. Therefore daily operating-reserves currently vary between 550 and 650 megawatts, and beyond 1977 they will vary between 800 and 1,000 megawatts.

Reserves may be in the form of either spare generating-capacity or a type of load that can be interrupted within a specified time to provide system relief, because load-shedding is essentially the same as adding capacity. By definition, then, Ready Reserve may include a type of interruptible power that can be taken off system within ten minutes. This gives some indication of how much Class-1 interruptible power could be sold in the form of

ONTARIO HYDRO-EAST SYSTEM
LONG TERM SITUATION WITH GENERATION CUTBACKS
END OF DECEMBER TO 1984



Illustrative Based on Preliminary Estimates - March, 1976

ready reserve as protection against a first major-contingency loss: namely between 400 and 500 megawatts in 1977 and beyond. However, since ready reserve also includes non-synchronized hydraulic units (0 MW at peak and perhaps as much as 2,000 MW at night) and Orenda combustion turbines (about 200 MW), and since between 400 and 500 megawatts of relief can be obtained over the tielines instantaneously, the ready reserve need not be made up entirely of interruptible power.

Ontario Hydro currently sells about 170 contracted megawatts of interruptible power Class 1 (currently known as Class B), which, because of diversity provides relief of about 85 megawatts at peak. As a conservative estimate, there is a potential for using double the present amount of Class-1 interruptible power as ready reserve.

For example, assume the system has 375 megawatts of spinning reserve and 200 effective megawatts of interruptible power Class 1, and that 750 megawatts of generation is lost at a peak period. The system could immediately pick up (say) 500 megawatts over the tielines; and within ten minutes it could pick up 375 megawatts with spinning reserve and 200 megawatts on the Orenda CTU's, thereby reducing the load over the tie lines to 175 megawatts. To relieve the tielines the load of Class-1 interruptible power could be cut; but there would be no Spinning Reserve available for protection against a second contingency loss. To restore the Spinning Reserve requires picking up load from spare capacity held in the form of slow-pickup reserve.

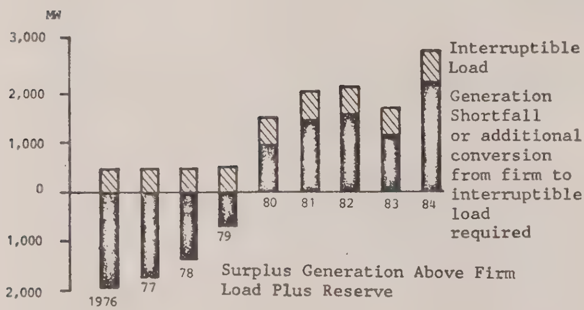
Ideally, then, the slow-pickup reserve (available within thirty minutes) should be large enough to protect the system against a second major-contingency loss (that is, some 800 to 1,000 megawatts). This gives some indication how much of a second type of interruptible power could be sold for this purpose, a type designated as class 2 (currently known as Class A).

At the present time, Ontario Hydro sells some 594 megawatts of Class-A interruptible power, which because of diversity translates into about 300 megawatts at peak periods. However, slow-pickup reserve includes synchronized thermal capacity , secondary sales (which can be withdrawn), industrial-type combustion turbines (about 200 MW) and capacity power purchases. Thus it is possible to cover some of a second major-contingency loss with non-interruptible power.

Under current conditions of excess generation capacity, present interruptible power sales exceed the requirements of the system for protecting the aimed for loss-of-load probability of one in 2,400. However, as was mentioned, the current situation will change greatly over the next several years. The following table shows the estimated shortfall in generation required to maintain a reliability of 2399 in 2400 for the month of December from 1976 to 1984 *assuming a required reserve margin of 28 per cent above firm demand.*

This situation may be represented graphically as in Figure 5.

Figure 5



As one can see, some action must be taken before 1980, to restore reliability to firm power users in that year and beyond. That could be accomplished by converting firm power to interruptible power, or (in other words), buying reserve generation from present firm-power customers in the form of discounts for using interruptible power instead.

Because of diversity, it is necessary to convert considerably more than (say), 1,500 megawatts to obtain 1,500 megawatts of relief; for instance, assuming an effectiveness of 50 per cent would require converting of 3,000 megawatts (it is to be noted that under adverse conditions, such as occurred in 1975, the effectiveness was only 30 per cent). However, there is an offsetting factor, in that as firm power is converted to interruptible, not only is the capacity requirement reduced, but the reserve requirement is also reduced. For example, for every 100-megawatt reduction in firm load required, generation is reduced by about 128 megawatts.

The remainder of this section analyses the situation under three different scenarios.

Scenario A

Under this scenario, Ontario Hydro would attempt to sell a further 200 effective megawatts of interruptible power (that is, reduce peak demand by 200 MW) in each of the years 1979 to 1984 inclusive, in order to restore reliability by 1983. The results are shown in the following Table.

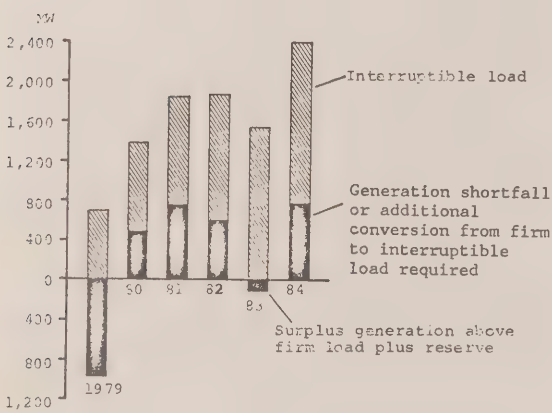
Year	1 hr.Firm Demand	Int. Load	Req'd Reserve	Firm Plus Reserve	System Capacity	Surplus (Deficit)
1976	14266	417	3994	18260	20194	1934
1977	15491	434	4337	19828	21575	1747
1978	16695	484	4675	21370	22725	1355
1979	17858	495	5000	22858	23564	706
1980	19071	522	5340	24411	23428	(983)
1981	20364	522	5702	26066	24577	(1489)
1982	21782	522	6099	27881	26293	(1588)
1983	23298	522	6523	29821	28634	(1187)
1984	24918	522	6977	31895	29601	(2294)

Year	Firm Demand	Int. Load	Req'd Reserve	Firm Plus Reserve	System Capacity	Surplus (Short-fall)
1979	17658	695	4944	22602	23564	962
1980	18671	922	5228	23899	23428	(471)
1981	19764	1122	5534	25298	24577	(721)
1982	20982	1322	5875	26857	26293	(564)
1983	22298	1522	6243	28541	28634	93
1984	23718	1722	6641	30359	29601	(758)

This scenario restores reliability to firm-power users in 1983 to approximately the goal of 2399 in 2400, but produces a shortfall in generation in all other years, which reaches a maximum of 758 megawatts in 1984. To provide the reliability in 1983 required 1522 effective megawatts of interruptible power, or some 3044 contracted megawatts of interruptible power sales assuming 50-per cent effectiveness. It is highly questionable whether Ontario industry could be expected to purchase such quantities of interruptible power in that stretch of time.

The results of this scenario are represented graphically in Figure 6:

Figure 6



Scenario B

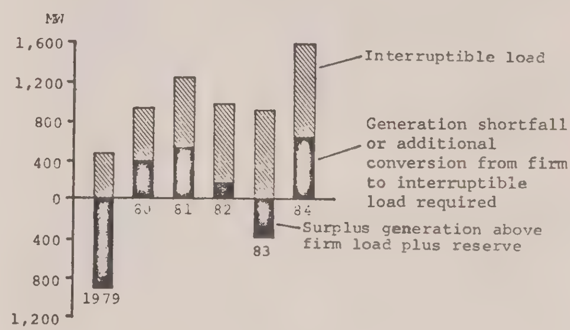
Under this scenario it is assumed that seasonal time-of-day rates based on marginal costs, and Ontario Hydro's efforts at conservation, would produce a reduction in the firm peak demand of 200 megawatts in 1979, 400 megawatts in 1980, 600 megawatts in 1981, and 800 megawatts in 1982 and beyond. In addition, Ontario Hydro would try to sell a further 100 effective megawatts of interruptible power in each of the years 1980 to 1984 inclusive.

The results are shown in the following Table.

Year	Firm Demand	Int. Load	Req'd Reserve	Firm Plus Reserve	System Capacity	Surplus (Short-fall)
1979	17658	495	4944	22602	23564	962
1980	18571	622	5200	23771	23428	(343)
1981	19564	722	5478	25042	24577	(535)
1982	20682	822	5790	26472	26293	(179)
1983	22098	922	6187	28285	28634	349
1984	23618	1022	6613	30231	29601	(680)

Again, this scenario provides more than enough capacity to restore the aimed for reliability to users of firm power in 1983. However, it still produces a shortfall in generation in all other years, the maximum being 630 megawatts in 1984. Nonetheless, in contrast with Scenario A, to provide adequate reliability in 1983 requires only 922 effective megawatts of interruptible power, or some 1844 contracted megawatts. The results of this scenario are represented graphically as in Figure 7:

Figure 7



Obviously, the more load that is shifted off the peak as a result of seasonal time-of-day rates based on marginal costs, the greater the improvement in reliability and the less the need for further sales of interruptible power to protect the reliability.

Scenario C

Under this scenario, the same assumptions are made about load reductions from pricing and conservation programs, the reserve requirement has been lowered to 25 per cent above firm and Ontario Hydro attempts to sell a further 100 effective megawatts of interruptible power in 1980 through 1982.

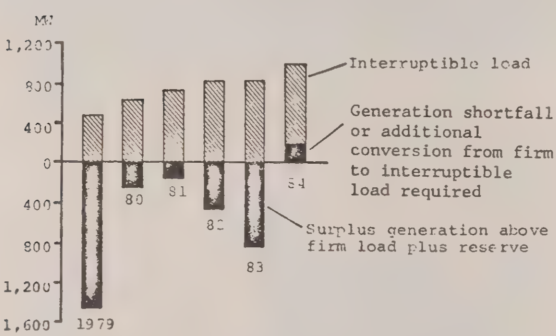
The results are as follows in the accompanying Table.

Year	Firm Demand	Int. Load	Req'd Reserve	Plus Reserve	System Capacity	Firm Surplus (Short-fall)
1979	17658	495	4415	22073	23564	1491
1980	18571	622	4643	23214	23428	214
1981	19564	722	4891	24455	24577	122
1982	20682	822	5171	25853	26293	440
1983	22198	.822	5550	27748	28634	886
1984	23818	822	5955	29773	29601	(172)

This scenario provides more than enough capacity to meet the requirement of reliability in every year except 1984, when there would be now a shortfall of only 172 megawatts. To provide this reliability requires 822 effective or 1644 contracted megawatts of interruptible power assuming 50-per cent effectiveness.

The results of this scenario are represented graphically as in Figure 8.

Figure 8



The assumptions made in Scenario C do not appear to be unrealistic. A movement from 764 contracted megawatts of interruptible power sold in 1976 to 1644 megawatts sold in 1984 is on the average a yearly increase of about ten per cent. Moreover, a reduction in the reserve requirement to 25 per cent seems far from unreasonable. Hence, it can follow that Ontario Hydro should aim for contracted sales of interruptible power amounting to about 1,000 megawatts in 1979, and for each of the years 1980 to 1982 actively promote the sale of a further 100 megawatts of interruptible power, both Class 1 and Class 2. This would provide about 300 effective megawatts of interruptible power Class 1 as ready reserve and 500 effective megawatts of interruptible power Class 2 as slow-pickup reserve by 1982.

If actual firm demands exceed the forecast demands by a significant amount in 1976 and 1977, then consideration would have to be given to earlier promotion of increased sales of interruptible power.

In a like manner, if after some experience has been gained with the open-bid marketing approach to sales of interruptible power, (as discussed in Section IV of this report), it appears that there is a greater potential market, then consideration should be given to further interruptible power sale increases. This would reduce the future amount of capacity and hence the capital requirements for the utility.

From the foregoing analysis it is recommended that:

> *Ontario Hydro should commence active promotion of the sale of additional interruptible power in 1979 such as to result in the sale of an additional 100 contracted MW of both Class 1 and Class 2 interruptible power in each of the years 1980 to 1982 to provide the system with approximately 300 effective MW of interruptible power Class 1 as ready reserve and 500 effective MW of interruptible power Class 2 as slow pickup reserve by 1982. Furthermore, if actual firm demand in 1976 and 1977 exceed the forecasts by a significant amount, consideration should be given to the advancement of active promotion of additional sales of interruptible power.*

IV. CURRENT AND PROPOSED PRICING-MECHANISMS

A. PRESENT PRICING-SYSTEM

Providing interruptible power yields savings to Ontario Hydro. The benefit of interruptible power could not be realized were it not for both the power system and interruptible power customers. The sharing of these savings is the inducement for the customer and utility to continue the service. The utility saves at least the annualized capital and operating cost of peaking capacity. Its only cost for supplying interruptible load is the cost of fuel, transmission, transformation, administration, and a share of operating and maintenance expense.

1. Method of Assessing the Value of Interruptible Power

The maximum value of interruptible power can be equated to displaced generation. This concept may be applied to pricing because generation displaced can be identified by type, and hence by cost per installed kilowatt. For the present and in the medium term, conventional fossil-fuelled units are expected to fill the role.

In recent years, the annualized cost of the Lennox Generating Station has been used in calculating the capacity discount component for interruptible power. Lennox was considered to represent capacity that could be changed to meet additional firm load resulting from conversion of interruptible load. The present method for establishing the discounts for interruptible power, as shown in Appendix V (using updated figures for 1977), is essentially the same as that recommended in the *Report on the Interim Study of Interruptible and Scheduled Power* dated 21 February 1975, which was tabled before the Ontario Energy Board during the 1975 hearing. However, in the long run, uncertainities in fossil fuel supply and cost forecasts cloud the planning process for generating stations. It follows that the type of generating capacity interruptible power can be considered to displace will change. It is therefore recommended that

> ***The formulae as shown in Appendix V should be adopted for establishing a fixed discount for interruptible power, but the capacity component of the discount should be based on the annualized cost of capacity as determined by the marginal-cost study: that is, the generating-plant component of the demand charge.***

The above recommendation implies continuing the current shared-benefit factor (50-50) for establishing a fixed discount off the firm demand rate. This figure is an arbitrary one; but since any other figure chosen would be just as arbitrary, it would be well to keep the present one for continuity's sake.

Appendix VI illustrates the discounts as calculated using figures from the marginal cost study conducted by National Economic Research Associates. Because the capital cost of the marginal plant in the study is less than that of the generating station used in Appendix V (Lennox GS), the discount is lower.

2. Advantages of the Present Pricing-System

1. Customers have become familiar with it.
2. The discount is relatively easy to calculate.
3. Customers need only decide whether they want interruptible at a fixed discount; they need not consider varying price-risk alternatives.

3. Disadvantages of Present Pricing-System

1. There is little theoretical or operational justification for sharing the savings in generation half-and-half between firm and interruptible customers. Benefits shared should be a function of market demand for the product and its supply. That is, if the demand for interruptible power were greater than the supply, an open-market mechanism would allocate a proportionally larger share of the benefit to the supplier. Ontario Hydro as supplier returns these benefits to customers taking firm power.
2. Attaching a fixed discount to interruptible power based on an arbitrary sharing of the savings can lock out potential customers. There may be potential customers who would buy interruptible power at a discount greater than the established fixed one but still less than the maximum one allowable to reflect the incremental cost of additional service. Therefore, this currently untapped market would add more to the revenues from interruptible power than to costs.
3. While potentially restricting entry to the market for interruptible power, the present pricing system also arbitrarily profits those customers whose costs of expected interruptions are covered more than adequately by the set discount.
4. Given that savings accrue to the Corporation when interruptible power is sold, a pricing system such as the present one, which does not maximize the benefits from the service, is deficient.
5. The current pricing system does not accurately reflect the market forces affecting utility supply and customer demand of interruptible power. It therefore distorts the proper price signals for interruptible power. This in turn distorts the marginal rates of substitution between interruptible power and alternative sources of energy.

4. Alternative Models for Pricing and Marketing

Several alternative models for pricing and marketing the supply of interruptible power were examined. A list of these alternative models follows.

1. *The Current Method*
2. *The Open-Market Choice Process.* Since this was the preferred alternative, it is elaborated upon in Part B.
3. *The Ratcheting-Discount Method.* This model is based on the hypothesis that customer requirements could best be satisfied by offering several categories of interruptible power with progressively larger discounts for longer cuts and higher probabilities of being cut. The approach provides for additional discounts for each interruption. This model is included as Appendix VII.
4. *Further Categories of Interruptible Power.* This is similar to the last alternative, but does not provide for additional discounts with each interruption. This model is included as Appendix VIII.
5. *Interruptible-Rebate Approach.* This approach offers year's-end rebates to interruptible customers who have received cuts. The basis of the rebates is twofold:
   a. Amount of interruptible power taken;
   b. Degree of customer inconvenience or cost as determined by Ontario Hydro's calculation.

An outline of the approach is presented in Appendix IX.

The methods as outlined in Appendix VII, "Ratcheting-Discount Method", and Appendix VIII, "Further Categories of Interruptible Power", are basically extensions of the present approach. They are an improvement upon the current fixed discount approach, in that they do afford the customer some leeway in choosing which class best suits his needs. However, most of the disadvantages of the present approach still apply.

The approach reviewed in Appendix IX, "Interruptible-Rebate Approach", is inconsistent with the nature of interruptible power. In the first place, applying a "typical customer's" inconvenience factor to unique and diverse companies is unacceptable. The variance in magnitude and intensity of different customers' reaction to the costs of interruptible power is too great to be averaged into a single factor. Secondly, in offering interruptible power for sale, Ontario Hydro is buying insurance against system failures. Thus Ontario industry assumes the risk in return for a discount. By contrast, the rebate approach is a no-insurance one. Ontario Hydro would be paying the customer for the costs he incurred from suffering an interruption. There could be little justification for such an obligation, unless Ontario Hydro were to sell power on the basis of its value to the customers rather than its cost to the utility.

The rest of this section will analyse the recommended method for pricing interruptible power. Because of the difficulties both the customer and Ontario Hydro will have in changing over from one pricing-approach to another, the following is recommended:

> ***Beginning in 1979, all potential customers for interruptible power should be offered interruptible power Class 1 and Class 2 at a fixed discount from the demand rate for firm power, before the start of a calendar year; and any interruptible supply not sold then should be offered to customers in the form of an open-market choice process.***

The implication of this recommendation will be clear at the end of the volume. Suffice it to mention here that this approach would permit any customer who so wished to buy interruptible power at a fixed discount from the firm demand rate. Should the demand for interruptible power at a fixed discount exceed the available supply, the service can be offered on a first-come-first-served basis. In the longer run, the decision to phase out fixed-price interruptible power would be based on the demand for the product in relation to demand for interruptible power within the open-market process.

B. PROPOSED INTERRUPTIBLE POWER PRICING-ALTERNATIVE

The open-market choice process is recommended because it will be consistent with the objective of efficiently allocating the resources devoted to producing electricity, at the lowest feasible cost.

An auction solves specific resource allocation problems. Given that a fixed amount of interruptible power must be parcelled out to a variable number of customers, there could be countless pricing methods. However, a competitive pricing scheme can maximize the benefits of the resource allocation, and so achieve economic efficiency. It must be stressed that the only reason for offering interruptible power at a fixed discount is to maintain continuity in rate structures. It is expected that the customers would see the advantages of the auction system and eventually discontinue buying interruptible power at a fixed discount.

Although the proposed system of pricing would be markedly different from the one used now, economic theory would go far to support it. A system that allowed the user to price the service at its marginal value would be efficient, rational, and self-stabilizing, and would not discriminate against either the user of the service or the subsidiary benefactor (the user of firm power).

1. The Mechanics

This pricing-system may be likened to a progressive open auction with competitive bidding. In developing this pricing-system, several bidding and auctioning-procedures were examined. These included progressive auction, sealed-bid tenders, the Dutch or regressive auction, and even the discriminatory auction as used to sell Treasury bills. These alternative procedures are briefly described in Appendix X. The procedure deemed most suitable for Ontario Hydro was the progressive open auction. This method was chosen because

1. Of all systems, it is the most likely to yield an optimal allocation of resources by equilibrating market supply and demand.[1]
2. Its flexibility and openness should lead to better customer participation, compared to other allocation methods.
3. No customer can become "locked in" to a particular bid. At the time of purchase, the customer has full information about the price and characteristics that Ontario Hydro has attached to interruptible power.
4. The method could yield more revenue than other auctioning procedures. Because of its flexibility and clear information, it might produce greater revenue for Ontario Hydro than a discriminatory auction.[2]

One can describe a hypothetical Ontario Hydro auction of interruptible power under three headings: Preparation, Operation, and Results.

Auction Preparation

First a certain amount of interruptible power would be put up for sale. This amount would be determined by the requirements of system planning and operations, as well as other considerations previously discussed in Sections I and II.

Secondly, joint probabilities of interruption in terms of frequency and length would be estimated for the coming year and projected for five years. Depending upon how precise they proved, these probabilities would be attached to discrete blocks of the interruptible power supply. Ideally, a normal curved distribution of probabilities would be available for the whole supply. The highest probabilities of interruption would be reserved for Class-1 interruptible power. As was mentioned previously, this information is essential to the auction approach.

At some specified time before the date of the auction, interruptible power would be offered for sale at a fixed discount. Specific probabilities of interruption would not be attached to fixed discount sales, since the blocks of interruptible power sold in this manner would be ranked along with the supplies sold in the auction. Depending, then, on where the fixed discount stood compared to discounts derived from the market, the probabilities of interruption could be anywhere along the distribution curve. Customers would be able to buy Class-1 or Class-2 interruptible power.

Remaining supplies of interruptible power would be available for the auction and available to any customer, the only constraint being that the minimum block for purchase would be 5,000 kilowatts. All interested parties would receive the necessary background information.

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[1]See William Vickrey, "Counter Speculation, Auctions and Sealed Tenders", *Journal of Finance* 16 (1961), pp. 8-37.
[2]See Steven Bolten, "Treasury Bill Auction Procedures: An Empirical Investigation", *Journal of Finance* 16 (1961), pp. 577-585.

For his part, the potential customer would realize that his calculations of expected cost of interruption would be a function of the joint probability of the frequency and length of interruption. A given customer's probability of interruption would depend on where he found himself placed within the total supply. (A customer's location relative to others and to the whole interruptible supply results, of course, from the price he is willing to pay for the product).

As with any auction, the final piece of information potential participants need would be the floor price. The floor price would equal the minimum unit revenue Ontario Hydro would require to recover its costs. It would be the price below which no bids would be accepted. In other words, it would equal the monthly demand charge for firm power, less the maximum discount per kilowatt available. This minimum price would reflect the marginal cost (or saving) to Ontario Hydro of an increment (or decrement) of interruptible power.

At the level of maximum discount for Class-2 interruptible power, the further savings in generating capacity from selling one more unit of interruptible power would barely offset the additional costs and loss in revenue of producing, transmitting and distributing that extra unit. Because generating plant used to supply interruptible power would have to be constructed in any case to provide reserve capacity, one could say the main cost in determining the floor price is fuel. However, fuel cost is the main component of the energy (kWh) charge and is not relevant here. More accurately, the appropriate demand (kW) floor price for Class-2 power would be calculated by subtracting the marginal annualized capital cost per kilowatt of a marginal plant from the price per kilowatt for firm power. The maximum discount for Class-1 interruptible power would include the savings inherent in having this type of interruptible power available as ready reserve. The costs included in the demand charge include generation, transmission, transformation, administration and some share of operation and maintenance. Using the results of the marginal cost study, Appendix XI shows the illustrative floor prices for 1978, 1979, 1980, and the maximum discounts for interruptible power.

When the customer has this information, he can undertake his own internal cost-benefit calculation. For any probability of interruption, a company would have the costs from expected cuts calculated beforehand. It would then be a relatively straightforward procedure to estimate the savings or discount from the firm power rate needed to offset those expected costs. To illustrate, a hypothetical example may be constructed, as in the accompanying Table.

Interruptible Blocks (MW)		Ontario Hydro Annual Interruption Probabilities (Number & Hours)	Customer X's Minimum Savings or Monthly Discount Required ($/kW)
Class 2 Most Reliable	200	Frequency 2 Average Duration 1	.80
Class 2 - 2nd Most Reliable	200	Frequency 6 Average Duration 1.5	1.30
Class 2 Least Reliable	200	Frequency 9 Average Duration 3	1.45
Class 1	200	Frequency 12 Average Duration 4	2.00
Total Int. Supply	800		
Class 2 Maximum Discount			1.50
Class 1 Maximum Discount			1.65

This example implies certain assumptions:

1. Interruptible power has been split into discrete blocks of reliability only for ease of illustration.
2. Cost of expected interruptions includes (besides value of lost production) any other relevant costs.
3. Company X has not adjusted Ontario Hydro's estimated probabilities of interruption. Some customers might manipulate the estimates they received to values which they considered more accurately portrayed their future chances of interruption. The adjustments could be made in either direction. For example, a company averse to risk could estimate its interruption costs on the maximum possible hours of interruption as specified in the contracts. In this way, if its offsetting minimum savings per kilowatt were still above the floor price for interruptible power, it could not lose. This would assume, of course, that it managed to purchase a block of interruptible power.

The hypothetical example portrays one situation where the minimum discount required would be greater than the floor price. Clearly, company X would not be in the market for Class-1 interruptible power.

Armed with cost-benefit (savings) tables, as above, potential customers would be ready to enter the Hydro auction. Much has been written about optimal bidding strategies for firms taking part in auctions. What use to make of these strategies is a matter for the firms themselves to decide, and therefore will not be considered in this report.

Auction Operation

As was mentioned, a specified amount of interruptible power Class 1 and Class 2 would be put up for sale.

Any supplies of interruptible power not sold at the established fixed discount would be available for auction. The principle of the auction would be simple: those purchasers who were willing to pay most for their interruptible power would receive it with the highest degrees of reliability. The lower the bid, the lower the degree of reliability, or the higher the chance of interruption compared to the highest bidder.

The bidding would start at the floor price. Ontario Hydro would accept bids on only one condition: that once submitted they could not be lowered. They might, however, be raised or withdrawn. All bids would be ranked from highest to lowest. A customer's position as against the others would decide his order of interruption, because the first company to be interrupted in times of system emergency would be the one that had paid the lowest price for the service. The auction would continue until all customers were satisfied with their relative positions.

Auction Results

At the end of the auction, all bids would be ranked from highest to lowest until either the available supply of Class-2 and Class-1 interruptible power was exhausted or a floor price for interruptible power was reached. It must be stressed that the blocks of Class-2 and Class-1 power sold under a fixed discount before the auction would be ranked with the bidders as well. Those purchasers of interruptible power who had a discount lower than the fixed rate would have a more reliable supply of interruptible power than those that opted for the traditional pricing system. Naturally, the opposite would hold for customers with a greater discount than the fixed amount. An example might prove helpful:

Assumptions:

1. 800 MW of interruptible power for sale (600 MW Class 2; 200 MW Class 1)
2. Fixed-Discount Sales
   a. Class 2 at $.75 per kW off the monthly firm-power demand rate: 250 MW
   b. Class 1 at $.85 per kW off the monthly firm-power demand rate: 0 MW
3. Maximum Allowable Discounts
   a. Class 2: $1.50 per kW per month
   b. Class 1: $1.65 per kW per month
4. Available for open auction: 550 MW
5. Amount of interruptible power sold on open market: 500 MW.

An example of how an auction might turn out appears in the accompanying Table.

Example of Auction Outcome

Company	Interruptible Sales (MW)	Discount ($)
	Class 2	
A	50	0.35
B	100	0.55
(I to N)	250	0.75
	(Fixed Discount)	
C	75	0.80
D	25	0.90
E	50	1.10
Sub-total:	550	
	Class 1	
F	100	1.20
G	25	1.35
H	75	1.52
Sub-total:	200	

Total Interruptible Power Sold: 750 MW
Unsold Interruptible Power: 50 MW

For simplicity, the sales of interruptible power have been aggregated somewhat unrealistically. Moreover, the actual spread between individual discounts should be considerably smaller.

In this hypothetical example, 14 companies A to N have bought interruptible power. Of the 800 MW available for sale, all but 50 have been taken. The unsold 50 MW of interruptible will not change the customer's probabilities of interruption. Using the previous example, there were varying probabilities of interruption for three 200 MW blocks of Class-2 interruptible power and the 200 MW of Class-1 interruptible power. In the hypothetical auction outcome, companies F, G, and H bought all the Class-1 interruptible. Companies C, D, and E and 50 MW of the fixed-discount group have the joint probabilities of interruption reflecting the second most reliable block of Class-2 curtailable power. Finally, companies A and B have interruptible power with the least chance of interruption. Note that the 50 MW of unsold interruptible power came out of the top (most reliable) and not the bottom of the range of interruptible power. This was so for the following reasons:

1. If customers substituted 50 MW of firm power for the unsold interruptible, the probability of interruption attached to the 50 MW of interruptible would be absorbed into the firm-power group. Hence, the reliability of firm power would decline slightly. In reality, the change would be difficult to measure.
2. If the 50 MW of interruptible power represented expected new sales, the unsold block of power would return to system reserve or idle capacity. Because it has become part of 'cold reserve', its function is to protect firm and interruptible power levels. However, since it takes eight hours for cold reserve to be synchronized to the system, it probably would not be available before interruptible was cut.

Therefore, either one of the above, or both together, insure that customers' probabilities of interruption will not change significantly.

One noteworthy item in the hypothetical auction is that no Class 1 interruptible power was sold under fixed discount. This would not be a surprising result, given that it would be illogical for a customer to take Class 1 interruptible power at a fixed discount which is less than the maximum discount for Class-2 interruptible. Clearly, the customer should only purchase Class 1 at a fixed discount if he is convinced that the lowest discount for Class 2 interruptible will be less than the fixed discount for Class 1.

Similarly, the decision to buy Class 2 interruptible power at a fixed discount is questionable, because of the lack of certainty about how reliable this interruptible power will be.

Assuming the customers bid rationally, the upper limit to the price of Class 1 interruptible would be the highest discount for Class 2. A customer would not want a lower discount for less reliable Class 1 than he could get for more reliable Class 2.

Whenever Ontario Hydro could not meet its needs for operating-reserve the first interruptible load to be cut would be Class 1, and the load of customers H, G, and F would be cut in that order. If that were still not enough after appropriate contingencies had been undertaken, Class 2 interruptible load would be shed. The order of cutting would be those with the highest discounts first, and so on. When one arrived at the blocks of interruptible power sold at a fixed discount, the load would have to be shed by rotation.

2. Relevance of the Recommended Pricing-System to Ontario Hydro

The open-market choice process should help Ontario Hydro reach an optimal allocation of interruptible power. Because the purchaser would decide for himself how much interruptible power he wished and what price he paid for it, the pricing decision would be made for Hydro. Moreover if demand for interruptible power exceeded supply, the amount available would be allocated within the market system.

Thus the system would present floor prices for interruptible power that reflected Ontario Hydro's marginal cost of providing the service. Furthermore, for any given level of reliability for the product, each customer would have an upper limit on the price he was willing to pay. These upper limits would reflect the marginal cost to the customer of incurring interruptions from taking interruptible power. The actual discounts would fall within these limits.

This system would thus provide a policy continuum within which any demand for interruptible power would be efficiently allocated.

For example, if demand for the service greatly exceeded supply, equilibrium prices for interruptible power would tend towards the customer's marginal cost or upper price limit. The result would be to absorb much of the customer's consumer surplus. Consumer surplus is the gap between total utility and total market value. The consumer receives more utility or value than he pays for. However, the consumer does not benefit at the expense of the seller. The wellbeing of all participants is increased by trade. These savings may be applied to reduce the reserve requirement and the total bill of the users of firm power. Applying the savings to the customer charge is recommended, since that is probably the inelastic part of the firm power user's demand for electricity. Thus applying the savings in this fashion would minimize the distortion of the price signal to the user of firm power, by not altering the marginal demand or energy rates.

As another example, if the supply of interruptible greatly exceeded the demand, then discounts might tend towards Ontario Hydro's floor price for interruptible. If so, use of the service would tend to be maximized, with the majority of the consumer surplus accruing to the customers taking interruptible power.

Either way, the bidding system would maximize the money benefits of using interruptible power, which is Ontario Hydro's main concern. How far the benefits accrue to either the firm or the interruptible customer depends on how the open market for interruptible power behaves.

3. Relevance of the Recommended Pricing-System for the Customer

Since the recommended pricing system would be based on a free-market allocation through an auction, the user of interruptible power would only buy if the option were better than any he could have had with fixed price interruptible or firm power. The natural substitutability between firm and interruptible power makes the individual companies' demand for the latter price elastic. In contrast, the characteristic of necessity on an individual basis often makes the demand for firm power somewhat inelastic. This relative inelasticity of firm power demands will be tempered somewhat by the ease of substituting other energy sources.

Present and potential users of interruptible power may face two different prospective situations under the recommended pricing system; neither will adversely affect the user.

a. Prospective Situation A: Interruptible Power Becomes Dearer

If after the bidding-process the average discount on interruptible power were to become less than present or historical levels, past users of the service would not be treated unfairly. Rather it should seem that earlier supplies of interruptible were underpriced and/or had different characteristics. The past customer would only renew his contract if buying interruptible power saved him enough money to offset the attendant risk. This situation in turn would assure that new entrants into the interruptible market would pay the marginal value of the product.

b. Prospective Situation B: Greater Discounts to Users of Interruptible Power

If interruptible power is now overpriced, or if its characteristics change, the pricing approach could lead to a greater discount for users. The end result might then be increased demand for interruptible power. If so, the established user might be able to obtain a larger discount for his interruptible power. The potential customer might then find it financially worthwhile to enter the interruptible market, because of the higher discount from the firm power demand rate.

c. The Firm User

The user of firm power will benefit under the new pricing-system. As was previously mentioned, it has been argued that the present system discriminates against him, because the interruptible user receives a discount for a service that at present may be as reliable as firm power.

In either of the two prospective situations previously described, the firm power customer would be better off under the proposed pricing scheme.

An important benefit to the firm user of providing interruptible service is that all revenues beyond the marginal cost of interruptible power accrue to the firm class.

If the average discount for interruptible is lower (as before under prospective situation A), then the firm user will find no one any longer acquires interruptible power at prices that do not reflect the value of the service provided.

Under prospective situation B, additional use of interruptible power might yield greater savings, which would be reflected in a lower customer charge or total bill for firm power.

To summarize:

1. The user of interruptible power will only enter the market if it is profitable for him to do so.
2. The user of firm power knows that, while the user of interruptible power is not in an unprofitable position, he is covering the costs of interruptible service while at the same time providing cost savings which are used to lower the total power cost to the firm user.

4. Possible Implications of the Pricing-Approach

One important question confronting a policy maker is, What effect will the new pricing recommendation have on the demand for interruptible power, and thus the whole system? Given knowledge of the present system and expected results from the one proposed, it is possible to enumerate potential and probable results.

As was mentioned previously, the results of the auctioning scheme depend on the level of interruptible power for sale, which will affect the availability and characteristics of interruptible power.

Given the potential for savings, more curtailable power might be put up for sale. However, rigidities in the supply of interruptible service would prevent any great fluctuations in the short run. Future supply decisions depend somewhat on the results of the bidding.

Regardless of how much interruptible power was to be sold, the important factor would be the degree of reliability of the service.

It is expected that curtailable power supplies would not become more reliable than they are now. Thus depending on circumstances, one would expect cuts in interruptible load to become more likely. This would be due mostly to the capital constraints imposed upon Ontario Hydro, which led to cutting back the generation program.

Whether the reliability of the service is greater or less than historical levels, an auctioning system will continue to efficiently allocate the resources used to provide curtailable service. To support this assertion, various implications of two possible situations are presented to illustrate probable adjustment processes. The two examples are the implications if 1.Interruptible power continues to be highly reliable, or 2.Interruptible power becomes less reliable.

a. Interruptible Power Continues to be Highly Reliable

Preliminary forecast data suggest the system may continue to have surplus power after supplying the interruptible load until 1979. This probability, combined with the possibility of limited growth in the supply of interruptible power offered for sale, could mean that in the short term interruptible power will remain highly reliable.

If so, the demand for interruptible power would probably increase. For the recommended auction approach has two inherent advantages to the customer that are lacking in current pricing-procedures.

1. *Clearer Information.* The potential customer would face a service with characteristics that would be measureable and have joint probabilities attached to them. Information which the recommended system would provide to the interruptible customer is:
   a. The varying probability of interruption (a five-year projection of joint probability of length and duration);
   b. A floor price below which the customer may not bid; and
   c. Better understanding of how the system works and how the customer is an integral part of it.
2. *Choice*. The recommended system, which would provide industry with a series of options, would be not only more efficient than current methods, but also better in terms of marketing psychology and public relations. The customer would no longer face a fixed system within which he would only participate if his expected costs were less than the fixed discount for interruptible power.

In everyday life, a company faces decisions that require some judgement. As far as possible, it will base that judgement only on sound financial principles and cost alternatives. The more alternatives the businessman has available, the better, because he realizes that as the number of his options and trade-offs increases, his chances of maximizing profits or minimizing costs improve, providing he undertakes sound financial action.

A company continually makes choices between trade-offs such as:

1. More capital vs less labour;
2. New capital machinery vs repairing old; or
3. Higher chance of return on investment vs more risk.

It is reasonable, then, to induce flexibility in the interruptible sales to companies who have had to remain flexible to survive. Flexibility in pricing means ease of self-adjustment to change, with less disparity in customer accumulation of economic surplus.

Given the foregoing two advantages, one would expect the price of interruptible to be bid upward somewhat. However, there may be token losses in interruptible demanded, because the unit price has increased with no change in its characteristics of high reliability. An offsetting factor, though, would be that the better information and choice should bring more firms into the interruptible market, since those who previously were locked out by a set discount rate now have other options available.

As long as the maximum allowable discount is below the current discount rate, the trade-off of cost savings against some degree of risk should allow for increased demand for the service.

The company already in the market will not leave as long as the potential for cost reduction remains. There might be complaints from some established customers, but they would largely originate from the loss of a pricing-approach by which they were profiting unduly.

b. Interruptible Power Becomes Less Reliable

The upshot of this could be either to decrease or to increase the demand for curtailable service.

At current fixed prices, making interruptible power less reliable would probably make it less attractive, and so reduce demand. Certainly those customers who currently pay a fixed price for very reliable interruptible power would have to re-evaluate their commitment if the characteristics of the service have changed with little compensating flexibility in price.

Herein lies an implicit advantage of the open-market choice process. Under the recommended system, decrease in reliability would not be at all certain to change the demand. Rather, the changes might occur on the pricing-side. If there were a greater attendant risk, the consumer might consider that interruptible power was worth his company's while, providing he could successfully bid for a larger discount. It may well be, therefore, that the demand for interruptible power would rise, because the discount off the demand rate for firm power would have increased enough to offset the increased probability of interruption.

5. Subsidiary Issues

a. Allowance for Resale of Interruptible Power.

The situation may arise where, for one reason or another, a customer wishes to sell some or all of his purchased interruptible power. The recommended system could include plans for meeting such contingencies. Any customer wishing to sell his inter-

ruptible power would be able to do so, provided that his sale blocks were equal to or larger than the minimum size. The sale of power would include all rights and obligations, especially those having to do with entering and leaving contracts for interruptible power. Ontario Hydro would have to be notified to complete the transfer of the interruptible contract.

In certain situations that might arise, cuts could be very hard to administer, since the customers might take to trading contracts to suit their particular situations, and the risks those situations carried with them, at any given time.
The allowance for resale of interruptible power would therefore be permitted, only insofar as it did not place heavy administrative burdens on Customer Service, Power Billing, and Operations.

b. Collusion Within the Bidding-System.

There might be some opportunity for collusion in participants' price bids. However, the relatively large number of expected participants (30 or more) should seem to preclude any all-inclusive agreements. It would be very hard to reach agreement when the participating number would necessarily be ranked, and so face varying probabilities of interruption. With many interruptible users taking part, there would be internal competition and haggling to reach the colluded agreement: so much so that the final result would probably differ little from that of an open auction.

Even if the former large constraints are removed and those with vested interests reach some type of agreement, any arranged bid must remain above Hydro's floor price if it is to be accepted. Therefore, while the most efficient free-market allocation of resources would not be achieved, the solution would still be efficient given the constraints outlined. In sum, the combination of the relative insignificance that interruptible power has, as a share of total customer production costs, combined with the strong competitive forces of an open auction approach, would form an imposing defence against the threat of collusion.

6. Long-Run Benefits of the Open-Market Choice Process

The competitive auction approach to interruptible power sales has two specific longer-term implications. This method of selling interruptible power acts, to some extent, as a long-run tool for supply planning and a revenue stabilizer.

a. Supply Forecasting.

Assume that in 1976 Ontario Hydro had a total reserve requirement of 4,400 megawatts. Interruptible power accounts for 800 megawatts of this, the remainder being composed of other types of reserve. If sales of interruptible power increased as a proportion of the total reserve requirement, some point would theoretically be reached where the market mechanism would be unable to sell any more. At this point, additional sales of interruptible power would have become (for all potential and actual customers) too risky to be offset by the maximum allowable discounts. Experience with this pricing-mechanism should aid forecasters and planners in future decisions about interruptible supply. The evidence for nearing the upper limit to the amount of interruptible power sold in any given stretch of time will be an average discount that approaches the floor price for the service. In fact, the theoretical optimum for Ontario Hydro would be where all customers were supplied, and the customer with the lowest bid paid the marginal cost of providing interruptible power.

b. Revenue Stabilizer.

Assume that in 1977 the Ontario economy enters a slump which affects electricity demand as follows:

1. 1976 actual: 13,800 MW
2. 1977 forecast: 14,200 MW
3. 1977 actual: 14,000 MW

Under these conditions, the competitive progressive auction approach to pricing interruptible power could act as a revenue stabilizer. In a period of slack in the economy, one might expect the demand for interruptible power to grow, as companies looked for ways to cut costs. The increased demands would force average prices in the open market up closer to the individual customers' margins. While providing increased revenues from interruptible power, this would also have the added revenue stabilizing effect of causing some customers to switch back to firm power.

As a converse situation, assume the economy enters into a boom or expansionary period, with the following distortion in forecast load:

1. 1976 actual: 13,800 MW
2. 1977 forecast: 14,200 MW
3. 1977 actual: 14,400 MW

(The cause of this unexpected rise in electricity demand, be it increased business sales or investment or technological change, is irrelevant to the analysis.)

As firm power demand unexpectedly increased, the reliability of first interruptible power, then firm power, would decrease. It is important to note that the reliability of firm power would decrease proportionally more than that of interruptible. Thus the incentive for customers to switch from firm power to interruptible power could outweigh their desire to do the opposite. This, then, would mainly aid system adjustment (less strain on firm-power loads).

If one were to outline a desperate prospective situation where there was serious generation shortfall, one might arrive at a perverse result where interruptible power was more reliable than firm power. This would cause interruptible prices to be bid to the maximum possible: that is, no discount off the demand charge for firm power. This situation could occur if (for example) the upper limit to interruption were eight hours a day while firm power was being cut an average of nine hours a day. The catalyst to such an improbable scenario could be loss of alternative energy supplies or large losses in generating-capability or some combination of the two.

While any such prospective situation is quite unlikely, there are also three significant factors constraining the perverse adjustment process and result.

1. Substituting electricity for other sources of energy would take time. Depending on the length of the lag, Ontario Hydro could have some time to increase generating capacity.
2. If customers switch to interruptible power at a proportionally greater rate than firm load growth, reliability of interruptible power will decrease. Naturally, if interruptible came to make up the whole reserve requirement, then the range of reliability of interruptible power would be wide (from very poor to approximately the same loss-of-load probability as firm power).

3. If because of the foregoing the demand for interruptible power decreased, then the relative reliability of interruptible power would generally increase. At some point, as compared to firm power, interruptible would look attractive again.

Thus the proposed approach to interruptible power sales, along with its relationship with firm power, would make both interruptible power and the system more self-stabilizing than before.

It is therefore recommended that

> ***The open market choice (auction) approach to sales of interruptible power should be conducted as described in this study, with all the constraints and clauses as specified therein.***

In recommending that, the study team is aware of (and shares) the concern expressed lest it should add to the administrative burden of various departments and divisions of the Corporation. One example of that is the problem of how to handle a changing list of customers for interruptible power, with their associated changing cutting-priorities. Another is the problem of running the auction itself, and all its implications for legal contracts, billing-procedures, and other matters. Such problems must be weighed against the benefits of the proposed system of pricing.

APPENDIX I: Description of Present Types of Interruptible and Scheduled Power

Ontario Hydro currently offers the following types of interruptible and scheduled power:

1. Interruptible Power, Class A

This class was designed to enable Ontario Hydro to reduce the amount of generating-capacity it would otherwise need to provide, by being able to interrupt the load whenever generating-capacity is inadequate to supply firm loads. It is subject to interruption during conditions of system emergency, defined as inadequate total capacity (for example, from forecasting-errors or scheduling-delays on new generation), inadequate energy capability (for example, exceptionally low water conditions), and inadequate operating reserves. At present these loads can be interrupted from Monday to Friday inclusive for 5 hours a day at most from March to November inclusive, 14 hours a day at most from December to February inclusive, and a maximum of 15 per cent of the hours in any month or 1295 hours a year.

Such loads are more susceptible to interruptions during the winter peak period from October to February. Where it is practicable, the customer receives two hours notice before an interruption, but under emergency conditions he may receive only short advance notice or none.

2. Interruptible Power, Class B

Besides providing savings in generating-capacity as described under Class A, this class was designed to enable Ontario Hydro to achieve operating-economies by reducing the total costs associated with providing necessary operating-reserves. Customers receive as much notice as practicable, but under certain conditions they may be asked to cut load at once without any advance notice.

For system emergency conditions, Class B is treated the same as Class A, and is more susceptible to cuts in the period from October to February. To achieve savings in operating-reserve, Class B is equally susceptible to cuts in any month of the year, and can be cut any day of the week. Class B customers are subject to maximum interruptions of 5 hours a day from March to November inclusive, 14 hours a day from December to February inclusive, and from a maximum of 15 per cent of the hours in any month or 1314 hours a year.

3. Scheduled Power, Class C

This class is available to industrial customers who are prepared to reduce load on a daily schedule of restricted hours, with a resulting saving to Ontario Hydro in meeting daily system peaks. The schedule of restricted hours is prepared by Systems Operations, and covers anticipated weekday winter evening peak periods and summer morning and afternoon peak periods. The maximum number of restricted hours is five a day; and there are no restrictions on Saturdays, Sundays, or statutory holidays.

4. Scheduled Valley-Hour Power

This class is available over existing 115 and 230-kilovolt facilities in amounts of 10,000 kilowatts or more, and is available for use between 11:00 p.m. and 7:00 a.m. daily throughout the year.

Calculation of the Value of Cuts in Interruptible B Load 1976 and 1977

APPENDIX II

March 12, 1976

Reference: "Economic Value of Interruptible Loads in Day-to-Day Operation" - memorandum to Mr. E.G. Bainbridge from Mr. W.H. Winter, 23 July, 1973, updated by Mr. P.D. Henderson on 29 January, 1975.

Assumptions:

1. The average percentage of time that interruptible B loads were considered useful for remains unchanged from that calculated in the above references, namely:

Period	Percentage of Time
Winter	39%
Summer	34%

2. Amount of Interruptible B loads = 119 MW

3. Average fuel costs for 1976: $1.28/MBTu.
   Average fuel costs for 1977: $1.41/MBTu.

Winter (January, February, November, December)

Start-up costs - Lakeview AEI unit (warm)	$1,592
Increased fuel costs per day (12 hours)	$1,435
Total increased costs per day	$3,027

Number of working days in the period: 117
Average percentage of time B loads were utilized: 39% x 117 days = 45.63 days

Value of interruptible B loads in winter = 45.63 x $3,027 per day =	$138,129

Summer (March through October)

Start-up costs - Lakeview Parsons unit (warm)	$1,592
Increased fuel costs per day (12 hours)	-$ 584 (savings)
Total increased costs per day	$1,008

Number of working-days in period = 169
Average percentage of time B loads were utilized - 34% x 169 days = 57.46 days

Value of interruptible B loads in summer = 57.46 days x $1,008 per day =	$57,920
Total value of Interruptible B-type customer loads during 1976 as operating-reserve is approximately -	$196,000
The projected value of these loads in 1977 has been calculated to be approximately -	$216,000

April 12, 1976

Economy Savings Due to
Interruptible 'B' Cuts During 1975

During 1975 there were two Interruptible 'B' cuts, one amounting to 0.125 MWh and a second one for 81.0 MWh.

Only the second cut amounted to any appreciable savings, as this was used to displace combustion turbine units. The worth of the displacement is calculated as follows:

a) Energy Savings = 81 MWh x (47.0 - 11.31)$/MWh
= $2,891.00

where 47.0 $/MWh = average running cost of CTU's
11.31 $/MWh = average system incremental cost

b) CTU Startup Cost Savings = 5 x $115 = $575.00

c) Total Savings = 2891 + 575 = $3,466.00

ILLUSTRATIVE COMPUTATION OF THE ECONOMIC CHOICE BETWEEN THE USE OF STORED ENERGY-INTENSIVE PRODUCTS AND THE CONTINUED MANUFACTURE OF THESE PRODUCTS DURING PERIODS OF REDUCED AVAILABILITY OF GENERATING CAPACITY (1975 DOLLARS)

Line No.	Item	Chlorine[b] Caustic Soda	Liquid[a] Cryogen	Portland Cement "Dry" Process	Portland Cement "Wet" Process	Arc-Furnace Steel	Reference
1	Market Value Per Ton	$ 133.57	$ 92.00	$ 33.50	$ 33.50	$ 187.67	(c)
2	Maximum Number of Interruptions Per Year	30	30	30	30	30	APCI Experience
3	Average Hours Per Interruption	5	5	5	5	5	APCI Experience
4	Restarting Time - Hours Per Interruptions	4	4	1	1	1.67	(d)
5	Hours Lost Per Interruption	9	9	6	6	6.67	Lines 3 + 4
6	Total Hours of Lost Production	270	270	180	180	200	Lines 2 x 5
7	Production (Tons/Hour)	2.13	1	1	1	1	
8	Lost Production (Tons/Year)	575	270	180	180	200	Lines 6 x 7
9	Value of Lost Production[f] (Dollars/Year)	$76,803.00	$24,840.00	$6,030.00	$6,030.00	$37,543.00	Lines 1 x 8
10	Power Requirements (kWh/Ton)	1,408	900	128	120	510	(d)
11	Demand (kW)	3,000	900	128	120	510	Lines 7 x 10
12	Value of Lost Production[f] ($/kW/Year)	$ 25.60	$ 27.60	$ 47.10	$ 50.25	$ 73.60	Lines 9 ÷ 11

EXAMPLE WITH ONTARIO HYDRO DATA (1975 DOLLARS)

Line No.	Item	Chlorine[b] Caustic Soda	Liquid[a] Cryogen	Portland Cement "Dry" Process	Portland Cement "Wet" Process	Arc-Furnace Steel	Reference
1	Market Value Per Ton	$ 133.57	$ 92.00	$ 33.50	$ 33.50	$ 187.67	(c)
2	Maximum Number of Interruptions Per Year	18	18	18	18	18	
3	Average Hours Per Interruption	1.78	1.78	1.78	1.78	1.78	
4	Restarting Time - Hours Per Interruption	4	4	1	1	1.67	(d)
5	Hours Lost Per Interruption	5.78	5.78	2.78	2.78	3.45	Lines 3 + 4
6	Total Hours of Lost Production	104.04	104.04	50.04	50.04	62.10	Lines 2 x 5
7	Production (Tons/Hour)	2.13	1	1	1	1	
8	Lost Production (Tons/Year)	221.61	104.04	50.04	50.04	62.10	Lines 6 x 7
9	Value of Lost[f] Production (Dollars/Year)	$29,600.45	$9,571.68	$1,676.34	$1,676.34	$11,654.31	Lines 1 x 8
10	Power Requirements (kWh/Ton)	1,408	900	128	120	510	(e)
11	Demand (kW)	3,000	900	128	120	510	Lines 7 x 10
12	Value of Lost[f] Production ($/kW/Year)	9.87	10.64	13.10	13.97	22.85	Lines 9 ÷ 11

(a) "Liquid Cryogen" produced in a weight ratio of 9.31 tons of liquid oxygen-nitrogen for each ton of liquid argon (liquid oxygen-nitrogen mixture is costed for a single product -- assumed 25,800 SCF/ton mixture).

(b) "Chlorine-Caustic Soda" produced in a weight ratio of 1.128 ton caustic soda for each ton of chlorine.

(c) For Liquid Cryogen -- APCI price schedule, October 1975.

(d) For Liquid Cryogen and Liquid Hydrogen - personal knowledge.

For Arc-Furnace Steel - 50% of time required to load and tap one melt, per Battelle Report, page I-3.

For Portland Cement - estimated.

(e) For Liquid Cryogen and Liquid Hydrogen - APCI experience.

For Chlorine and Caustic Soda - Industrial Chemicals, W. L. Faith, Donald B. Keyes and Ronald L. Clark, Editors, 2nd Edition, John Wiley and Sons, Inc., New York, New York, 1957, page 257.

For Portland Cement - Chemical Process Industries, R. Norris Shreve, Third Edition, McGraw-Hill Book Company, 1967, page 171.

For Arc Furnace Steel - Final Report on Technical and Economic Analysis of the Impact of Recent Developments in Steelmaking Practices on the Supplying Industries, Batelle Memorial Institute, Columbus, Ohio, 1964, page A-12.

(f) Cost of energy consumed for restart not included due to varying electric rates.

Revised 13 November 1975/slb

Source: Provided to Ontario Hydro by Mr. Ed Bielawski as a consequence of studies undertaken by AMPCO.

APPENDIX V: CALCULATION OF THE FIXED DISCOUNT

1. Average Annual Cost of Capacity (Lennox G.S.)

Installed capacity (4 units)	2152 MW
Total estimated capacity cost	$489 million
Capital cost per kW	$ 227.23
Annual fixed charges (9% over 30-year life)	$ 22.09/kW
O & M (including overhead)	$ 5.17/kW
Total Average Cost	$ 27.26/kW

2. Generation Capacity Discount: Class 1 and 2

Basic Capacity Discount/kW/Month = (Y1972/Y1977)* x ($YKsr/12)

Y1972 = Interruptible 1 and 2 loads as forecasted in 1972 for 1977 in terms of generation capacity = 380 MW.

Y1977 = Estimated average monthly billing-demand of Interruptible 1 and 2 loads in 1977, the basis on which the shared benefits would be distributed through discounts in monthly bills = 564 MW.

*NOTE: This component will change each year.

$Y = Estimated annual cost of generation associated with generation capacity savings = $27.26/kW/year.

K = Composite adjustment factor which consists of the following product:
- f - floor cutting tolerance = 0.97
- a - additional administration cost factor = 0.95
- t - transition factor (to firm power or vice versa) = 0.95

s = Shared benefits factor = 0.5

r = Generation reserve factor = 1.25

From the formula, the calculated generation capacity discount for 1977 for both Class 1 and 2 is 84 cents per kW per month.

NOTE: The transition factor - t - .95 will not be required if the recommendation with the regard to interruptible to firm switching is adopted.

3. Calculation of "Ready Reserve" Discount

Class 1 Only

Discount for ready reserve savings = $\frac{sp}{12b_p}$

where

s = shared benefits factor = 0.5
p = estimated savings on 5-minute pickup reserves
= minimum $220,000
= maximum $500,000
b_p = estimated average monthly billing demand of loads eligible for savings = 160 MW (1977 estimated Class 1 loads)

From this formula, the calculated ready reserve discount for Class-1 loads for 1977 is:*

minimum = 6 cents/kW/Month*
maximum = 13 cents/kW/Month*

4. Summary of Calculated Discounts per kW per Month

Class of Power	Capacity	Ready Reserve	Total
Interruptible 2	84 cents		84 cents
Int. 1 minimum	84 cents	6 cents	90 cents
Int. 1 maximum	84 cents	13 cents	97 cents

Approved for 1976

Class of Power	Capacity	Ready Reserve	Total
Interruptible 2	79 cents		79 cents
Interruptible 1	79 cents	40 cents	$1.19

APPENDIX VI: Calculation of the Fixed Discount with Marginal-Cost Data: 1975

1. Marginal Cost of Production (Capacity):

Long-run Unit Investment $193.75/kW

Total Marginal Cost $21.33/kW/yr.

Cost of marginal plant converted to 1975 dollars and adjusted for planned reserve margin of 25 per cent.

2. Generating-Capacity Discount

Using the formula as presented in Appendix V (excluding generation reserve factor r), the calculated generating-capacity discount is 52 cents per kW per month.

Note: Generating-reserve factor (r) (1.25) is already taken into account in computing the marginal cost of production.

3. "Ready Reserve" Discount

Calculation as in Appendix V.

APPENDIX VII: Ratcheting-Discount Method

Some customers can withstand longer interruptions than others, and some can withstand more frequent interruptions than others, and still others can interrupt with less notice than others. Therefore pricing may attempt to take these differences of operation and value to the system and cutting-probabilities into account.

It has also been suggested at the hearings of the Energy Board that true interruptible power should only be interrupted for capacity savings and not for reasons of economy. The latter could be either a separate class of service or an optional arrangement with each individual customer. Another concern at the hearings was that domestic supply should not be interrupted to support export sales. These concerns should be taken into consideration.

To overcome some of the objections to the present conditions of supplying interruptible power, the following pricing-methodology was considered:

1. Capacity Interruptible Power

Ontario Hydro would offer for sale a specified amount of capacity interruptible power in minimum amounts of 5,000 kilowatts. Ontario Hydro would not make day-to-day emergency purchases from interconnected systems to prevent cutting capacity interruptible loads. Where practicable, customers would receive at least two hours' advance notice; but under emergency conditions, they might receive very short notice or none.

Capacity interruptible power would be offered in the following three categories under the conditions specified (the discounts shown are illustrative only).

1. *Capacity Interruptible Power: Class 1*. Subject to interruption seven days a week for each month of the year, and for as long as five hours a day, to a maximum of five per cent of the total hours in the month, and five per cent of the total hours in any 12 consecutive months.

The discount from the firm demand rate would be 20 per cent, plus an additional one per cent per month for each interruption to a maximum of an additional five per cent.

2. *Capacity Interruptible Power: Class 2*. Subject to interruption seven days a week for each month of the year, and for as long as ten hours a day, to a maximum of ten per cent of the total hours in the month and ten per cent of the total hours in any 12 consecutive months.

The discount from the firm demand rate would be 30 per cent, plus an additional one per cent per month for each interruption to a maximum of an additional five per cent.

3. *Capacity Interruptible Power: Class 3*. Subject to interruption seven days a week for each month of the year for as long as 14 hours a day, to a maximum of ten per cent of the total hours in the month and ten per cent of the total hours in any 12 consecutive months.

The discount from the firm demand rates would be 40 per cent, plus an additional one per cent per month for each interruption to a maximum of an additional five per cent.

The pricing-method outlined above for capacity interruptible power would give customers choices into which they might be able to fit the interruptible portion of their plant load. It would set definitive limits on the total number of hours of interruptible in each month and over a 12-month period. In addition, it would provide for extra compensation for those customers who are interrupted more frequently due to such things as size of load available for interruption and geographical contingencies.

2. Planning of Interruptible Power in the Long Run

Ontario Hydro would have to estimate the total amount of interruptible power which it could expect to sell in the short and long-run terms. The equilibrium amount, as a proportion of total primary power, would be established by customers' choosing the amount they would agree to take in the various interruptible categories described in this proposal. Factors such as load growth, size of units installed, and changing probabilities of interruptions, would have to be taken into consideration in establishing the amount of interruptible power available for sale each year.

APPENDIX VIII: Alternative Classes for Interruptible Power

Since some customers can withstand longer interruptions than others and some can withstand more frequent interruptions than others, Ontario Hydro should offer more than one type of Interruptible Power for sale to meet the needs of its customers.

Capacity Interruptible Power

Ontario Hydro would offer for sale capacity interruptible power in minimum amounts of 5,000 kW. This class of power would enable Ontario Hydro to reduce the generating-capacity it would otherwise have to provide, and serve as a means of system relief under emergency conditions.

Capacity interruptible power would be offered for sale in the following classes:

1. Capacity Interruptible Power, Class 1

Subject to interruption seven days a week each month of the year for as long as five hours a day, to a maximum of five per cent of the hours in the month and five per cent of the hours in any 12 consecutive months.

The discount from the firm demand rate would be 20 per cent.

2. Capacity Interruptible Power, Class 2

Subject to interruption seven days a week each month of the year for as long as 10 hours a day, to a maximum of ten per cent of the hours in the month and ten per cent of the hours in any 12 consecutive months.

The discount from the firm demand rate would be 30 per cent.

3. Capacity Interruptible Power, Class 3

Subject to interruption seven days a week for each month of the year, for as long as 14 hours a day, to a maximum of ten per cent of the total hours in the month and ten per cent of the total hours in any 12 consecutive months.

The discount from the firm demand rate would be 40 per cent.

APPENDIX IX: Interruptible-Rebate Approach

A method of selling interruptible power was considered by which the savings the system actually realized through interruptible power would be made available to individual customers taking interruptible power to the extent of and in proportion to each customer's contribution to the total realized saving. Savings accruing to the interruptible-power customers would be based on the actual interruptions they incurred. The savings would be in the form of rebates paid at the end of the year to those interruptible customers who actually underwent interruptions.

The total dollar amount available for rebates would be determined by the total amount of interruptible power load actually used. Savings realized by the system through using interruptible power would depend on the actual interruptible power demand during the year. This figure would, of course, only be available at the end of the year. Once the actual total interruptible demand for the year was known, the corresponding estimated savings as set out more than a year earlier could be established. These savings would be the base from which individual customers' rebates could be calculated.

The rebate paid to an individual customer would depend on the degree of inconvenience that customer suffered during the year. Inconvenience would be defined by a general inconvenience formula and the frequency and length of interruption.

APPENDIX X: Alternative Auctioning-Procedures

1. Sealed Tenders

The required procedure would be to ask for bids on the understanding that interruptible power would be sold to the highest bidders. Those tendering the lowest discounts would be offered the most reliable interruptible power. The greatest drawback to this approach is that potential customers would not know the reliability of the interruptible power they bought.

2. Dutch Auction

Prices would be announced in descending sequence (or, in other words, discounts announced in ascending sequence, from 1 cent per kilowatt per month up), with the first and only bid being the one that ends the transaction. The most reliable interruptible power would go to the first successful bidder, the next most reliable to the next successful bid, and so on. If demand for interruptible power exceeded supply, there might be the perverse result that interruptible power with lower reliability would sell for more than more reliable interruptible power.

In fact, this type of pricing-mechanism turns into essentially a game in the technical sense. Each bidder, in attempting to determine at what point he should be ready to make a bid to obtain the greatest expectation of gain, will need to take into account whatever information he can obtain about the bids others might make; and their bids in turn would depend on their expectations about how the first bidder would behave. To put in a bid as soon as the price has come down to the full value of the object to the bidder maximizes the probability of obtaining the object, but guarantees that the gain from securing it will be zero. As the announced price is lowered, the possibility of a gain emerges, but as the gain thus sought increases with the lowering of the point at which a bid is to be made, the probability of securing this gain diminishes. Each bidder must therefore try to balance these two factors in terms of whatever knowledge he has about the probable bids of the others.

Therefore, besides having a potential for somewhat perverse results, this bidding-approach definitely favours the sophisticated and well-informed bidder.

3. Discriminatory Auction

In the discriminatory auction, treasury bills to different bidders are sold at different prices. The supply of bills is cleared by accepting the highest bid first and then descending until the supply is depleted at what is called the stopout price.

There are basically two types of bids. The non-competitive bid for 182-day and 91-day bills is usually employed by the less sophisticated, smaller investor. Each non-competitive bidder is assured of receiving the quantity he bids for at the average price paid in that week's auction.

The competitive bid is used by the more sophisticated bidder. Each competitive bid specifies a price and amount, and each competitive bidder may submit as many bids as he chooses. The bills remaining after the non-competitive demand is met are allotted to each competitive bidder in descending order of price until the supply is exhausted.

The discrimination lies in the fact several different prices are paid for precisely the same commodity. This approach, then, does not apply to the sale of interruptible power, because of the different characteristics of reliability that may be attached to any given amount of the service.

CALCULATION OF MAXIMUM DISCOUNTS AND FLOOR PRICES FOR INTERRUPTIBLE POWER FOR 1978, 1979, AND 1980

MAXIMUM DISCOUNTS FROM FIRM DEMAND RATE (FLOOR PRICES)* FOR CLASS 1 AND 2 INTERRUPTIBLE POWER

	1978	1979	1980
Class 2			
(1) Total Marginal Demand Costs	\$2.26/kW/mo	\$2.56/kW/mo	\$2.80/kW/mo
(2) Diversity Factor**	.67	.67	.67
(3) Class 2 Max. Discount (1) x (2)	\$1.51/kW/mo	\$1.71/kW/mo	\$1.88/kW/mo
(4) Class 1 "Ready Reserve" Discount***	\$0.13/kW/mo	\$0.13/kW/mo	\$0.13/kW/mo
(5) Class 1 Max. Discount (3) + (4)	\$1.64/kW/mo	\$1.84/kW/mo	\$2.01/kW/mo

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* Calculation of floor prices proceeds as follows:
Firm Demand Rate - Maximum Discount = Floor Price
Separate computation is needed for Classes 1 and 2.

** The diversity multiplier is the ten-year average of annual five-year forecast interruptible over the estimated average monthly billing-demand of interruptible.
Example: Y1972 = Interruptible 1 and 2 loads as forecast in 1972 for 1977 in terms of generation capacity = 380 MW
Y1977 = Estimated average monthly billing-demand of Interruptible 1 and 2 loads in 1977 = 564 MW
Therefore Y1972/Y1977 = 380/564 = .67

*** See Appendix I for calculation.

		1978	1979	1980
(1)	Cost of marginal plant*	$208.53	$232.09	$254.60
	+ planned reserve margin of 20%	41.71	46.42	50.92
	= Total Long-Run Unit Investment	$250.71	$278.51	$305.52
(2)	Revenue Requirement Related to Capital Investment	10.61%	10.61%	10.61%
(3)	Allowance for Property Tax Repayments **	.2%	.2%	.2%
(4)	Total (2) + (3)	10.81%	10.81%	10.81%
(5)	Annualized Costs (4) x (1)	$ 26.60	$ 30.11	$ 33.03
(6)	Total Working Capital Materials and Supplies (1) x 2.0% ***	5.01	5.57	6.11
(7)	Revenue Requirement for Cash Working Capital (6) x 10.0%****	0.50	0.56	0.61
(8)	Total Demand - Related Costs (5) + (7)	27.10	30.67	33.64

All sources not identified are from NERA Marginal Cost Study.

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* Escalation forecasts after Economic Forecasting Services
1. Engineering - Labour and Material Escalation
   A. Generation Projects - Major Equipment Mechanical

Ontario Hydro, Office of the Chief Economist, January, 1976.

** Estimated by NERA on the basis of forecast tax payments and plant in service from data in Ontario Hydro Financial Forecast 1975-1980, Comptroller's Division, 750224.

*** Based upon analyses undertaken by NERA of the relationship between materials and supplies and gross investment.

**** Overall cost of capital to Ontario Hydro during the planning period.